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EMISSIONS FROM FUEL OIL COMBUSTION

An Inventory Guide

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Public Health Service

EMISSIONS FROM FUEL OIL COMBUSTION

ATMOSPHERIC EMISSIONS FROM FUEL OIL COMBUSTION

An Inventory Guide

by

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U. S. DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Public Health Service

Division of Air Pollution

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PREFACE

The total inventory of pollution emitted to the atmosphere from all types of sources in a community will provide part of the basis for consideration of the possible need for control of air pollution. This review was prepared to provide a guide for inventorying and controlling emissions arising from combustion of fuel oil. Information was collected from the literature. Additional data were provided, upon request, by several power companies. This review is limited to information on oil used as a source of heat or power (exclusive of process heaters). The data were abstracted, assembled, and converted to common units of expression to facilitate understanding.

Although much has been done to increase the accuracy of sampling methods, stack sampling is not an exact science and is subject, in some cases, to significant errors. Because of this limitation and the many design and operating variables, there is a wide range of values for emission of any given pollutant. In a literature review of this nature, where all the published values are impartially reported, it is appropriate to recommend those values reported most frequently. In most cases, this has been done. When the most frequently reported value was not compatible, however, with theoretical possibility, the value recommended was selected in the light of good judgment.

Emission values are subject to continual change as data are made available. It is expected that current investigations on the air pollution arising from the combustion of fuel oil will give more complete information on this subject. Investigations now being conducted include: (1) a survey of emissions, including polynuclear hydrocarbons, by the Division of Air Pollution, Public Health Service, at the Robert A. Taft Sanitary Engineering Center in Cincinnati, Ohio; (2) a literature search, by the Bureau of Mines at Laramie, Wyoming, for fuel oil desulfurization processes; (3) a study of means for removal of sulfur dioxide from flue gases, by the Bureau of Mines at the Bruceton Station, Pittsburgh, Pa.; and (4) a survey of emissions from the combustion of fuel oil in residential and light industrial furnaces, sponsored by the American Petroleum Institute.

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CONTENTS

	Page
Summary	1
Introduction	1
Fuels	4
Aspects of Oil Combustion	15
Oil Preparation	15
Oil Combustion	16
Smoke Formation	16
Acidic Smut Formation	16
Emissions from Large Installations	17
Oxides of Nitrogen (NO_x)	17
Theoretical Considerations	17
Emission Rates	19
Tangentially Fired Units	19
Horizontally Fired Units	19
Variables Affecting Emissions	21
ring Rate	21
Two-Stage Combustion	22
Load Factor	22
Excess Air	22
Windbox Pressure	23
Flue Gas Recirculation	23
Fuel Pressure and Temperature	23
Other Variables	25
Sulfur Dioxide (SO_2)	25
Theoretical Considerations	25
Emission Rates	26
Sulfur Trioxide (SO_3)	26
Theoretical Considerations	26
Emission Rates	28
Variables Affecting Emissions	31

Page

Other Gaseous Emissions 32
Particulate Emissions 32
Emission Rates 32
Particle Size 34
Chemical Composition and Description 35
Variables Affecting Emissions 36
Efficiency of Combustion 36
Atomization 38
Windbox Air Admittance 38
Burner Tilt 39
Excess Air 39
Flue Gas Recirculation 39
Sootblowing 39

Emissions from Small Installations 40
Oxides of Nitrogen (NO_x) 40
Sulfur Dioxide (SO_2) 41
Sulfur Trioxide (SO_3) 42
Other Gaseous Emissions 43
Particulate Emissions. 44

Control of Emissions 45
Oxides of Nitrogen (NO_x) 45
Sulfur Dioxide (SO_2) 45
Sulfur Trioxide (SO_3) 45
Smoke and Organic Gases 46
Acidic Smuts. 46
Particulates 46

References. 49

Appendixes 55

Appendix A: Detailed Data on Large Source Emissions.

Appendix B: Detailed Data on Small Source Emissions.

Appendix C: Method of Reporting the Data.

ABSTRACT

This review provides a guide for the inventorying and control of emissions arising from the combustion of fuel oil. Information was collected from the published literature and other sources. The report is limited to information on oil used as a source of heat or power (exclusive of process heaters). The data were abstracted, assembled, and converted to common units of expression to facilitate understanding. From these data, emission factors were established that can be applied to fuel oil combustion to determine the magnitude of air-contaminating emissions. Also discussed are the compositions of fuel oils; the preparation and combustion of fuel oil; and the rates of emission, their variables, and their control.

ATMOSPHERIC EMISSIONS FROM FUEL OIL COMBUSTION

An Inventory Guide

SUMMARY

The kinds and amounts of atmospheric emissions arising from the combustion of fuel oil are summarized in Table 1. The data in this table are divided into two groups, one for large sources (1,000 hp or larger) and the other for small sources (smaller than 1,000 hp).

In general, large sources produce more nitrogen oxides (NO_x) but less soot than the small sources. This is because of the higher flame and boiler temperatures characteristic of large sources. Small sources emit relatively larger amounts of hydrocarbons because of the small flame volume, the large proportion of relatively cool gases near the furnace walls, and, frequently, because of improper operating practices.

Table 1 contains values that may be used in making an inventory of emissions from combustion of fuel oil. After the surveyor has ascertained the amount of fuel used and the sulfur content of the fuel, he can estimate the quantities of stack emissions by the application of data in Table 1 and by judgment based on pertinent information in this report. It must be remembered that these values are general averages and can only provide rough estimates for the total emissions from a number of sources. Emissions from any one installation may vary considerably from those estimated by use of data in the table.

INTRODUCTION

Twenty years ago oil was considered to be a "clean" power source. Compared to coal, its use results in emission of approximately 90 percent less particulate matter. Oil combustion units do, however, emit many pollutants into the air: nitrogen oxides, sulfur oxides, and particulate matter are those most commonly of interest at this time. Other emissions are carbon monoxide, aldehydes, carbon, organic acids, and unburned and partially burned hydrocarbons, which are usually emitted in relatively larger amounts either from small sources or from inefficiently operated large sources. [1]

Table 1. SUMMARY OF EMISSIONS FROM FUEL OIL COMBUSTION [a, b, c]

Gaseous and particulate emissions	Large source emissions (1,000 hp or more)						Small source emissions (1,000 hp or less)					
	Extreme range,		Usual range,		Recommended value for emission surveys,		Extreme range,		Usual range,		Recommended value for emission surveys,	
	ppm in the stack gas	lb/1,000 lb oil	ppm in the stack gas	lb/1,000 lb oil	ppm in the stack gas	lb/1,000 lb oil	ppm in the stack gas	lb/1,000 lb oil	ppm in the stack gas	lb/1,000 lb oil	ppm in the stack gas	lb/1,000 lb oil
NO_x as NO_2[d]							0-630	0-18	0-140	0-4	320	9.0
horizontal	0-1,020	0-28	300-700	8.3-19	470	13	--	--	--	--	--	--
tangential	160-400	4.4-11	180-280	5-7.7	210	5.8	--	--	--	--	--	--
SO_2[e]	(52-520)S	(2.0-20)S	(440-520)S	(17-19.9)S	(510)S	(19.6)S	(0-520)S	(0-20)S	(365-520)S	(14-19.9)S	(510)S	(19.6)S
SO_3[e]	0-76	(0.063-2.9)S	6-24	(0.363-0.69)S	18	(0.30)S	(0-68)S	(0-3.4)S	(0-6.5)S	(0-0.31)S	(5.2)S	(0.25)S
CO[f]	0 - >100	0 - >1.7	--	--	0.3	0.005	0-1,100	0-194	0-120	0-2	15	0.25
Aldehydes[f]	0-67	0-1.2	--	--	--	0.07	0-180	0-3.3	0-33	0-0.6	14	0.25
Hydrocarbons and other organics[f]	--	0-5	--	--	--	0.4[f]	--	0-5	--	--	--	0.25
H_2S[f]	<50	<1	--	--	(n)	(n)	<50	<1	--	--	(n)	(n)
HCN[f]	<58	<1	--	--	(n)	(n)	<58	<1	--	--	(n)	(n)
HCl[f]	<46	<1	--	--	(n)	(n)	<46	<1	--	--	(n)	(n)
NH_3[f]	0-98	0-1	--	--	(n)	(n)	0-98	0-1	--	--	(n)	(n)
H_2[f]	--	--	--	--	(n)	(n)	0-5,800	0-7.0	--	--	(n)	(n)
Particulates	0.005-0.205[g]	0.15-6.3	0.025-0.060[g]	0.82-1.8	0.033[g]	1	0-0.33[g]	0-10	0.033-0.13[g]	1-4	0.049[g]	1.5

[a] This table is based on values reported in the literature, and even questionable values, such as zero, are given. Values given in ppm or gr/scf are at 12 % CO_2, 32°F., and 1 atm.

[b] -- Indicates insufficient data.

[c] (n) Indicates negligible value.

[d] If the type of unit is not known, use the values for the horizontal units.

[e] S indicates that the percent sulfur in the oil should be multiplied by the number in parentheses (the sulfur content of No. 6 fuel oil is usually 1.6% by weight). Example: If the number is 205 and the oil has 1.6% sulfur, the SO_2 emission would be 20 times 1.6, or 32 lb SO_2/1,000 lb oil fired.

[f] Based on limited information; validity open to question.

[g] gr/scf.

Steam generation plants operate over a wide range of conditions, and designs of larger plants vary widely. The rates of emissions from these units are affected by variable operating conditions and by nature of the fuel used. An indication of how emissions are affected by operating variables is given in Table 2.

Table 2. EFFECTS ON EMISSIONS OF INCREASING OPERATING VARIABLES [a]

Increasing operating variables	NO_x	SO_2	SO_3	Particulates
Percent load	I	-	I	-
Fuel temperature	D	-	I	D
Fuel pressure	D	-	I	D
Excess air	I	-	I	D
Percent CO_2 in stack	D	-	D	I
Dirt in firebox	I	-	I	I
Flue gas recirculation	D	-	-	I
Flame temperature	I	-	I	D
Stack temperature	-	-	I	D
Percent sulfur in oil	-	I	I	I
Percent ash in oil	-	-	D	I

[a] I means increase; D means decrease; - means no change.

Information was collected from the published literature and from other sources on stationary equipment for combustion of oil, mainly furnaces, boilers, and power plants (exclusive of process heaters). All data obtained have been included in this report, even though some are very probably inaccurate. The pollution sources are divided into two categories, large (1,000 hp or larger) and small (smaller than 1,000 hp). Unless otherwise stated, the emissions are reported in parts per million (ppm), by volume, or grains per standard cubic foot (gr/scf), corrected to 12 percent CO_2, or in pounds of pollutant per 1,000 pounds of oil fired. One standard cubic foot (scf) is taken as one

at 32°F and 1 atmosphere of pressure, on a dry basis. In oil combustion, 12 percent CO_2 in the stack gas corresponds to approximately 25 percent excess air or 5.5 percent O_2 in the stack gas. The newer boilers normally operate with about 14 percent CO_2 in the stack. When a boiler is referred to as operating at "normal load," it is usually operating at about 85 percent of its maximum continuous capacity.

Detailed emission data are given in appendixes A and B. Appendix A contains data for large sources, and Appendix B, data for small sources. Appendix C illustrates the method used in this report for graphically presenting the data.

Several factors were used to convert values found in the literature to uniform terms for this report, when necessary. These factors were as follows:

1-bbl oil = 42 gal
1-lb oil fired = 215 scf of stack gas at 12 percent CO_2 (dry)
1,000 hp = 34,500-lb steam/hr = 2,500-lb oil/hr (assuming 75 percent efficiency)
Percent CO_2 = 16.2 - 0.775 X (where X = percent O_2 in the stack)

When data on composition of residual oil were not given in material reviewed, the following fuel analysis was assumed:

86 percent carbon, 10 percent hydrogen, and the balance H_2O, O_2, N_2, sulfur, and ash; 18,300 Btu/lb; 12° API* or 8.2 lb/gal.

FUELS

Crude oil used as raw material in petroleum refining consists of a whole series of hydrocarbons varying from dissolved, fixed gases to heavy, nearly solid compounds. Certain fractions of crude petroleum, which may be separated by simple distillation, have the necessary properties for use as a fuel oil. Some hydrocarbons suitable for fuel oil are also produced by thermal or catalytic cracking. Except in unusual and relatively unimportant circumstances, the only commercial liquid fuels sufficiently cheap for power generation and for industrial heating are certain fractions of petroleum oil. [2]

*API: American Petroleum Institute.

The fuel oils used in small installations (smaller than 1,000 hp, or 34,500-lb steam/hr, or 2,500-lb oil/hr) are generally kerosene, diesel fuel, and grades 1 through 6 fuel oils. The kind of fuel oil used depends upon the size of the unit. The most common fuel for domestic units is grade 2. Larger units, up to 200 hp, generally take grade 4; up to 1,000 hp, grades 4 to 6; above 1,000 hp, grade 6 exclusively, or residual oils. Use of kerosene and diesel oil is usually confined to units smaller than 200 hp.

Typical properties of the light petroleum fuels are shown in Table 3. Tables 4 and 5 show the NBS* Commercial Standards Specifications for fuel oils and general classifications of fuel oils, respectively. Table 6 shows the maximum, minimum, and average gravity (in ^{o} API) and sulfur content for fuel oils used in five regions of the United States. The regions are shown in Figure 1. Table 7 shows the sales of distillate fuel oils (grades 1 through 4 and kerosene) and residual fuel oils (grades 5 and 6 and some crude oil) in each state for 1960. [6]

The fuel oil used most in boilers producing steam at a rate of 34,500 lb/hr or greater (1,000 hp or more) is called Bunker C. Other names for Bunker C and similar oils are: residual, high-viscosity, heavy, grade 6, or Pacific Standard 400. [2, 4] The range of properties for this fuel, as used in the United States in 1961, is listed in Table 8.

Grade 6 fuel oil is residual oil – a residue left after the lighter fractions, fuel-oil distillates, kerosene, and gasoline have been removed from the crude oil by distillation. During this process the ash-forming constituents and sulfur-bearing compounds originally present in the crude oil are concentrated in the residual portion. With the development of improved refining processes, larger proportions of the charged crude are removed as distillate and motor fuel stock, leaving less residual oil, which may contain higher concentrations of sulfur and ash than residual oils of a few years ago. [7]

Bulk fuel oil is sold in the United States in multiples of the 42-gallon barrel, at 60^{o}F. The heat content ranges from 18,000 to 19,000 Btu/lb, the average being 18,300. [2, 4, 7] Residual fuel oil is approximately 86 percent carbon, 10 percent hydrogen, 1.0 percent water, 0.5 percent nitrogen, and the remainder sulfur and ash. [2, 4] The sulfur content of residual oils is usually about 1.6 percent. [5] In 1961, however, the sulfur concentration varied in The United States from 0.34 to 4 percent, by weight (Table 8).

*NBS: National Bureau of Standards.

Table 3. TYPICAL PROPERTIES OF LIGHT PETROLEUM PRODUCTS (Reference 3)

Fuel properties	Kerosene	Premium diesel oil
Gravity, API, 60° F	41.9	37.1
Initial boiling point, °F	336	360
Distillation:		
10% recovered at °F	370	426
50% recovered at °F	437	502
90% recovered at °F	510	585
End point, °F	546	646
Flash point (P-M)[a], °F	130(TCC)[b]	164
Viscosity, Saybolt sec, 100°F	...	35.1
Diesel index	...	55.8
Sulfur, %	0.037	0.41
Cetane No., ASTM[c]	...	52
Conradson carbon residue, 10% bottoms	0.01	0.07

[a] (P-M) - Pensky-Martens closed tester (ASTM D93-42).

[b] (TCC) - Tag closed-cup tester (ASTM D56-36).

[c] ASTM - American Society for Testing Materials.

The composition of the ash in fuel oils varies greatly; the presence of a large number of elements has been detected. Normally, sulfur, aluminum, calcium, iron, nickel, silicon, sodium, and vanadium are found in complex organic forms in the oil. Other elements have also been found in the ash in very small quantities: barium, chlorine, chromium, copper, gold, lead, molybdenum, silver, strontium, thallium, tin, uranium, and zinc.[7, 8] A general analysis of the ash from oils (after burning under laboratory conditions) from different areas is shown in Table 9.

Figure 1. Geographical areas of the national survey of burner fuel oils, Bureau of Mines regions, 1961 (Reference 5).

[a] Low-sulfur fuel oils used in connection with heat treatment, nonferrous metal, glass and ceramic furnaces, and other special uses may be specified in accordance with the following:

Distillate fuel, grade	Sulfur (max), %	Residual fuel, grade	Sulfur (max), %
1	0.05	5	No limit
2	1.0	6	No limit
4	No limit		

Other sulfur limits may be specified only by mutual agreement between the purchaser and the seller.

[b] It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless, in fact, it meets all requirements of the lower grade.

[c] The exposed copper strip shall show no gray or black deposit.

[d] Lower or higher pour points may be specified whenever required by conditions of storage or use; these specifications shall not require a pour point lower than 0°F under any conditions.

[e] The 10% point may be specified at 440°F maximum for use in other than atomizing burners.

[f] The amount of water by distillation plus the sediment by extraction shall not exceed 2%. The amount of sediment by extraction shall not exceed 0.50%. A reduction in quantity shall be made for all water and sediment in excess of 1%.

[g] Formerly, a distillate oil for use in burners requiring a low-viscosity fuel. Now incorporated as part of No. 2 oil. Not now part of NBS std.

GPO 901-819-2

Table 4. NBS COMMERCIAL STANDARDS SPECIFICATIONS FOR FUEL OILS[a] CS12-48 (EFFECTIVE SEPT. 25, 1948. REPLACING STANDARD CS12-40), (Reference 4)

Grade of fuel oil[b]	Description	Flash point, min °F	Pour point, max °F	Max water and sediment, % by volume	Max carbon residue on 10% bottoms, %	Max ash, % wt	Max distribution temp, °F			Saybolt viscosity, sec,				Kinematic viscosity, centistokes,				Gravity, min °API	Corrosion (copper strip), 3 hr at 122°F[c]
							10% point,	90% point,	End point,	Universal, at 100°F		Furol, at 122°F		At 100°F		At 122°F			
										Max	Min	Max	Min	Max	Min	Max	Min		
1	A distillate oil intended for vaporizing pot-type burners and other burners requiring this grade of fuel	100 or legal	0	Trace	0.15	...	420	...	625	...	...	...	...	2.2	1.4	...	...	35	Pass
2	A distillate oil for general-purpose domestic heating, for use in burners not requiring No. 1 fuel oil	100 or legal	20[d]	0.10	0.35	...	[e]	6.75	...	40	...	...	...	(4.3)	...	...	...	26	...
3[g]																			
4	An oil for burner installations not equipped with preheating facilities	130 or legal	20	0.50	...	0.10	...	...	...	125	45	...	...	(26.4)	(5.8)	...	...	...	...
5	A residual-type oil for burner installations equipped with preheating facilities	130 or legal	...	1.00	...	0.10	...	...	...	...	150	40	...	...	(32.1)	(81)	[illegible]	...	...
6	An oil for use in burners equipped with preheaters permitting use of high-viscosity fuel	150	...	2.00[f]	...	...	...	...	...	...	...	300	45	...	...	(638)	(92	...	...

4	An oil for burner installations not equipped with preheating facilities	24-25	7.538-7.587	145,000-145,600	24-26	7.490-7.587	144,300-145,600
5	A residual-type oil for burners equipped with preheating facilities. Sold as Bunker B. Preheat suggested: 170° to 220°F	18-22	7.686-7.891	146,800-149,400	18-22	7.686-7.891	146,800-149,400
6	An oil for use in burners equipped with preheaters permitting use of high-viscosity fuel. Bunker C. Preheat suggested: 220° to 260°F.	14-16	7.998-8.108	150,700-152,000	14-16	7.998-8.108	150,700-152,000

[a] Since gravities are not included in commercial standards (excepting minimum gravities of 35 for No. 1 oil and 26 for No. 2 oil), this table is unofficial, based on trade practices under code CS12-40.

Table 5. GENERAL CLASSIFICATION OF FUEL OILS [a] (with range of gravities, heat values, and comparison of old specifications, CS12-40, with those of Sept. 25, 1948, CS12-48). (Reference 4)

Grade	Description	Present specifications, CS12-48			Former specifications, CS12-40		
		Gravity, °API	Lb/gal	Btu/gal	Gravity, °API	Lb/gal	Btu/gal
1	A distillate oil intended for vaporizing pot-type burners and other uses requiring a volatile fuel	35-40	6.879-7.085	135,800-138,800	38-40	6.879-6.960	135,800-137,000
2	A distillate oil for general purpose domestic heating, for use in burners not requiring No. 1. Moderately volatile	26-34	7.128-7.490	139,400-144,300	34-36	7.043-7.128	138,200-139,400
3	Formerly, a distillate oil for use in burners requiring a low-viscosity fuel. Now incorporated as part of new No. 2 oil standards	...	.....	.....	28-32	7.215-7.396	140,600-143,100

Table 6. PROPERTIES OF FUEL OILS USED IN THE U. S. - 1961 (Reference 5)

Fuel oil grade	Property	Eastern region			Southern region			Central region			
		Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	
1	°API, 60°F	39.5	42.9	46.2	39.8	42.7	44.7	39.5	42.5	46.1	
	sulfur, wt/%	0.007	0.069	0.17	0.01	0.068	0.21	0.005	0.107	0.48	
2	°API, 60°F	26.6	35.3	45.8	31.1	35.5	47.7	26.6	35.1	39.3	
	sulfur, wt/%	0.04	0.228	0.65	0.04	0.249	0.72	0.071	0.299	0.81	
4	°API, 60°F	9.0	21.4	31.6	16.9	a	27.9	14.1	20.5	27.9	
	sulfur, wt/%	0.18	0.84	2.12	0.27	a	1.92	0.27	0.90	2.12	
5	°API, 60°F	7.1	17.2	21.9	12.5	15.2	17.6	12.4	16.5	20.1	
	sulfur, wt/%	0.28	1.17	2.50	0.28	1.77	3.10	0.57	1.52	3.5	
6	°API, 60°F	-3.33	12.7	19.2	5.4	11.3	14.3	-3.33	10.1	23.0	
	sulfur, wt/%	0.53	1.34	3.40	0.34	1.58	3.36	0.42	1.47	4.0	

Fuel oil grade	Property	Rocky Mountain region			Western region			ASTM standards		Combined total	
		Min	Avg	Max	Min	Avg	Max	Min	Max	Number of samples	Avg
1	°API, 60°F	39.5	41.8	45.7	35.6	40.7	46.7	35	--	163	42.3
	sulfur, wt/%	0.006	0.113	0.41	<0.001	0.131	0.31	--	0.5	163	0.094
2	°API, 60°F	27.1	35.7	40.7	27.1	34.9	43.0	26	--	186	35.3
	sulfur, wt/%	0.029	0.324	1.06	0.029	0.419	0.93	--	1.0	186	0.286
4	°API, 60°F	10.0	19.6	31.0	10.0	18.4	31.0	--	--	31	20.7
	sulfur, wt/%	1.32	1.43	1.5	1.32	a	1.5	--	--	31	0.99
5	°API, 60°F	1.9	12.7	20.8	2.7	12.6	17.6	--	--	64	15.0
	sulfur, wt/%	0.28	1.84	3.5	0.90	1.83	3.5	--	--	64	1.58
6	°API, 60°F	1.5	9.3	19.1	1.5	7.6	13.4	--	--	144	10.5
	sulfur, wt/%	0.516	2.02	4.0	0.80	1.91	4.0	--	--	144	1.60

[a] No averages were computed since only two samples were represented for this test.

Table 7. SALES OF FUEL OILS IN 1960, thousand barrels
(Reference 6)

States	Distillate fuel oils (Grades 1 to 4 and kerosene)	Residual fuel oils (Grades 5 and 6 and crude oil used as fuels)
Alabama	1,007	4,202
Alaska	1,723	695
Arizona	546	95
Arkansas	307	474
California	4,977	78,660
Colorado	1,137	1,785
Connecticut	21,643	14,450
Delaware	2,476	6,081
District of Columbia	2,544	2,387
Florida	3,126	28,978
Georgia	1,673	6,413
Hawaii	145	5,613
Idaho	2,625	201
Illinois	32,490	25,676
Indiana	20,415	12,856
Iowa	8,445	1,021
Kansas	1,039	2,246
Kentucky	1,476	314
Louisiana	1,484	8,596
Maine	6,539	5,742
Maryland	10,660	16,490
Massachusetts	48,594	38,942
Michigan	26,739	11,242
Minnesota	11,339	6,363
Mississippi	89	338
Missouri	7,202	2,970
Montana	1,205	1,950
Nebraska	2,064	377
Nevada	589	202
New Hampshire	4,240	2,324
New Jersey	40,799	42,705
New Mexico	764	166
New York	71,488	76,586
North Carolina	9,665	4,537
North Dakota	2,376	655
Ohio	13,833	11,382
Oklahoma	617	1,108
Oregon	6,093	5,453
Pennsylvania	36,627	42,643
Rhode Island	7,619	9,502
South Carolina	3,375	4,634
South Dakota	2,254	58
Tennessee	926	184
Texas	5,340	21,463
Utah	1,112	5,552
Vermont	2,614	498
Virginia	9,312	17,448
Washington	13,226	9,179
West Virginia	487	1,451
Wisconsin	19,322	4,275
Wyoming	1,015	1,710
U. S. total	477,402	548,872

Table 8. PROPERTIES OF GRADE 6 FUEL OIL, 1961 [a]
(Reference 5)

Property	Min	Max
Gravity, °API	-3.33	23.0
Flash point, Pensky-Martens closed tester, °F	15.2	365
Viscosity, Furol, at 122°F, sec	13.7	415
Sulfur content, wt %	0.34	4.00
Ramsbottom carbon residue on 100% sample,	4.9	23.6
Ash, wt %	0.002	0.3
Water and sediment, vol %	0.0	1.0
Pour point, °F	-10	90

[a] The extreme ranges of various properties of fuel oil found in the United States in 1961.

Table 9. ANALYSIS OF ASH IN VARIOUS OILS, [a, b] as wt %
(Reference 9)

Reported as	Calif.	Mid Cont	Tex.	Pa.	Kan.	Iran	Iran
SiO_2	38.8	31.7	1.6	0.8	10.0	52.8	12.1
Fe_2O_3, Al_2O_3, TiO_2	17.3	31.8	8.9	97.5	19.1	13.1	18.1
CaO	8.7	12.6	5.3	0.7	4.8	6.1	12.7
MgO	1.8	4.2	2.5	0.2	1.3	9.1	0.2
MnO	0.3	0.4	0.3	0.2	Trace	Trace	Trace
V_2O_5	5.1	Trace	1.4	--	0.4	14.0	38.5
NiO	4.4	0.5	1.5	--	0.6	1.4	10.7
Na_2O	9.5	6.9	30.8	0.1	23.6	--	--
K_2O	--	--	1.0	--	0.9	--	--
SO_3	15.0	10.8	42.1	0.9	36.4	2.6	7.0
Chloride	--	--	4.6	--	0.1	--	--

[a] After burning under laboratory condition.

[b] 1938 data.

ASPECTS OF OIL COMBUSTION

Oil Preparation

Fuel oils must be vaporized before they can be burned. There are two different ways of doing this. The oil may be vaporized by heating within the burner unit or the oil may be atomized mechanically, producing fine oil droplets that may be vaporized. Burners in the first group, usually called vaporizing burners, are fired only with light oils. They are sometimes used in smaller space heaters with pot-type burners. They have very little application in the power field.[2, 10, 11]

If oil is to burn in the short time it is in the combustion chamber of a furnace, it must be in the form of small particles that expose as much surface per unit of volume of oil as possible to the heat in the chamber. The necessary atomization of the oil may be effected in three basic ways: by forcing oil under pressure through a nozzle, as in the "gun-type" burner; by use of centrifugal force, as in the "rotary-cup" burner; and by use of steam or air under pressure to inject the oil into the combustion chamber, as in "steam-atomization." Mechanical means that effect the atomization of oil in "rotary-cup" burners consist essentially of an oil cup, which is driven by a motor or air turbine, and an air nozzle or ring. The cup spins at speeds from 3,500 to 10,000 rpm. This motion tears the oil into droplets by centrifugal action. The steam- or air-atomizing burners use pressures ranging from 100 to 1,000 psi, as do the "gun-type" burners.[10, 12]

Besides atomizing the oil to achieve rapid vaporization, the burner must also disperse the particles of oil in such a manner that they mix with air, stripping off layers of oil from the droplets as they move through the air. This requires a high degree of turbulence. The great relative motion between the oil and the air also produces a uniform mixture in the combustion zone.[10]

Before the oil reaches the burner it is passed through a strainer or filter to remove sludge. This filtering process prolongs pump life, reduces burner wear, and increases the combustion efficiency.[10]

Grades 5 and 6 oil must be heated before they can be pumped to the burner efficiently. For good atomization, viscosity of these oils must be maintained in the range of 130 to 150 Saybolt Universal. This requires heating the oil to temperatures of 170 to 260°F.[2, 10, 11]

Oil Combustion

There are two kinds of hydrocarbon combustion: hydroxylation and decomposition. Hydroxylation or blue-flame burning takes place when the hydrocarbon molecules combine with oxygen and produce alcohols or peroxides that split into aldehydes, mainly formaldehyde, and water. The aldehydes burn to form CO_2 and H_2O. Decomposition or yellow-flame burning takes place when the hydrocarbons "crack" or decompose into lighter compounds. The lighter compounds then "crack" into carbon and hydrogen, which burn to form CO_2 and H_2O. [2, 4, 10, 12]

A mixture of yellow- and blue-flame burning is ideal. This type of burning is indicated when CO_2 in the dry stack gas is 12 to 14 percent. This stack gas composition corresponds to provision of approximately 15 to 30 percent excess air, depending on properties of the oil. [2, 4, 10, 12]

Smoke Formation

Smoke from oil-burning units is the result of incomplete combustion. An efficiently operated furnace should not smoke, since smoke is a sign that unburned and partially burned hydrocarbons are being emitted to the atmosphere. Incomplete atomization of the oil caused by improper fuel temperature; dirty, worn, or damaged burner tips; or improper fuel or steam pressure may cause the furnace to smoke. A poor draft or improper fuel-to-air ratio may also cause a furnace to smoke. Other factors that may cause a smoking fire are: poor mixing and insufficient turbulence of the air and oil mixture, low furnace temperatures, and insufficient time for fuel to burn completely in the combustion chamber. [10, 12]

Acidic Smut Formation

"Acidic smuts" are generally large particles, approximately one-fourth inch in diameter, containing metallic sulfates (usually iron sulfate) and carbonaceous material. Smut formation is a result of the condensation of water vapor and SO_3 on cold metal surfaces. The metal surface is defined as cold when its temperature is below the flue-gas dew point, which is approximately 300°F. The metal is corroded, forming the metallic sulfate. The metallic sulfate in turn absorbs carbonaceous particulates from the flue gas. The smut eventually flakes off and is carried out of the stack by the flue gas. [13]

EMISSIONS FROM LARGE INSTALLATIONS

Oxides of Nitrogen (NO_x)

THEORETICAL CONSIDERATIONS

Air contains approximately 21 percent oxygen (O_2) and 79 percent nitrogen (N_2) by volume. When oil is oxidized with air at high temperatures, the composition of the main combustion products is essentially 12 percent CO_2, 5 percent O_2, and 83 percent N_2, by volume. Other compounds, however, are also formed in small concentrations, some of which are air pollutants. One class of pollutants is referred to as NO_x— a general term that includes the oxides of nitrogen, such as NO, NO_2, N_2O_4, and N_2O_5. During combustion, oxygen and nitrogen gas combine to form NO as follows:

$$N_2 + O_2 \rightleftharpoons 2NO \qquad (1)$$

If time permits, this reaction will continue to equilibrium, but it does not go to completion as does the carbon to carbon dioxide reaction. The NO will, however, react with more oxygen and form NO_2 and other NO_x products. The N_2 to NO equilibrium may shift in either direction, depending upon many variables. If the concentration of one of the gases is increased, the equilibrium will shift to the opposite side. There is an abundance of nitrogen but very little oxygen present for this reaction. If the amount of oxygen (excess air) is increased (without reducing the flame temperature), the NO concentration will increase also, and the reverse is true. As the NO reacts with oxygen to produce NO_2, there is a reduction in the concentration of NO, which removes it from the equilibrium in reaction (1) above. The NO is replaced by reaction (1) returning to equilibrium.

Another variable that complicates this equilibrium is the motion of the gases through zones of different temperatures, pressures, and concentrations. Most of the NO is formed in the flame where very high temperatures are present. The residence time of the gases at this temperature is relatively short, however, and thus the NO reaction is prevented from reaching equilibrium. Figure 2 shows the theoretical concentration of NO, assuming typical fuel analysis, typical excess air, and a residence time of 0.5 second at various flame temperatures. [14]

The main factors in NO_x production are: the flame temperature (usually between 2,400 and 3,600°F), the length of time that combustion gases are maintained at the flame temperature, and the amount of excess air present in the flame. Distinctly different NO_x concentrations have been reported for two different basic designs of furnace, however. These designs are referred to as tangentially and horizontally fired fireboxes. The tangentially fired unit is built in such a manner that the flame is propagated in a cylindrical form. The unit is constructed to produce a spiral upward motion of the flame and combustion products around the walls of the cylindrical firebox. It is a relatively new and infrequently used design.

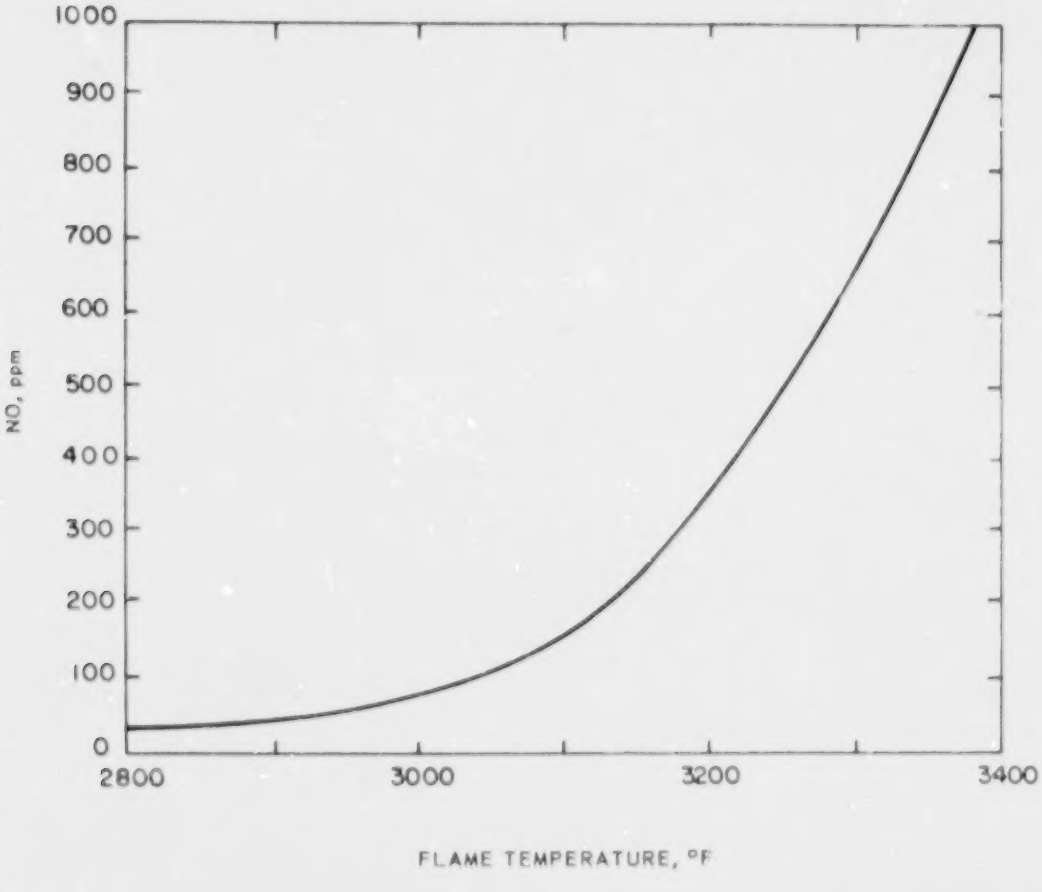

Figure 2. Theoretical formation of nitric oxide vs flame temperature (Reference 14).

Units fired other than tangentially are classified as horizontally fired units. These units are usually fired at right angles to the walls of the firebox but they may be fired at various angles. They may be fired on one or more sides, or from the bottom of the firebox. The firebox may be square, rectangular, or cylindrical. Horizontal firing tends to concentrate the hot gases in the center of the firebox.

EMISSION RATES

Tangentially Fired Units

NO_x emissions from tangentially fired units appear to be about one-half as great as those normally reported for horizontally fired units. Only a few authors have reported on emissions from tangentially fired units. Sensenbaugh reported a range of 200- to 400-ppm NO_x in the stack for this type of unit. [15] Sensenbaugh and Jonakin compiled many literature values for tangentially and horizontally fired units. These values ranged from 160- to 362-ppm NO_x in stacks from tangentially fired units. [14] All the data, including the experimental values, found in the literature for tangentially fired units are shown in Figure 3. The numeral 2 designates two-stage combustion, which will be discussed later. Figure 3 shows an extreme NO_x concentration range of 160 to 400 ppm in stack gas from tangentially fired units. The most common range is 180 to 280 ppm. The most common values reported in the literature are between 200 and 220 ppm, which may be lower than normal; the few references available, however, permit no better representation.

Horizontally Fired Units

All emission data, exclusive of that relating to tangentially fired units, are grouped under the classification "Horizontally fired units." Many general ranges for emissions from horizontally fired boilers have been reported, as follows:

Range NO_x as NO_2, ppm	References
330 to 915	1
500 to 700	15
100 to 900	15, 16
310 to 915	17, 18
275 to 600*	19*
400 to 600	20

*At stack conditions.

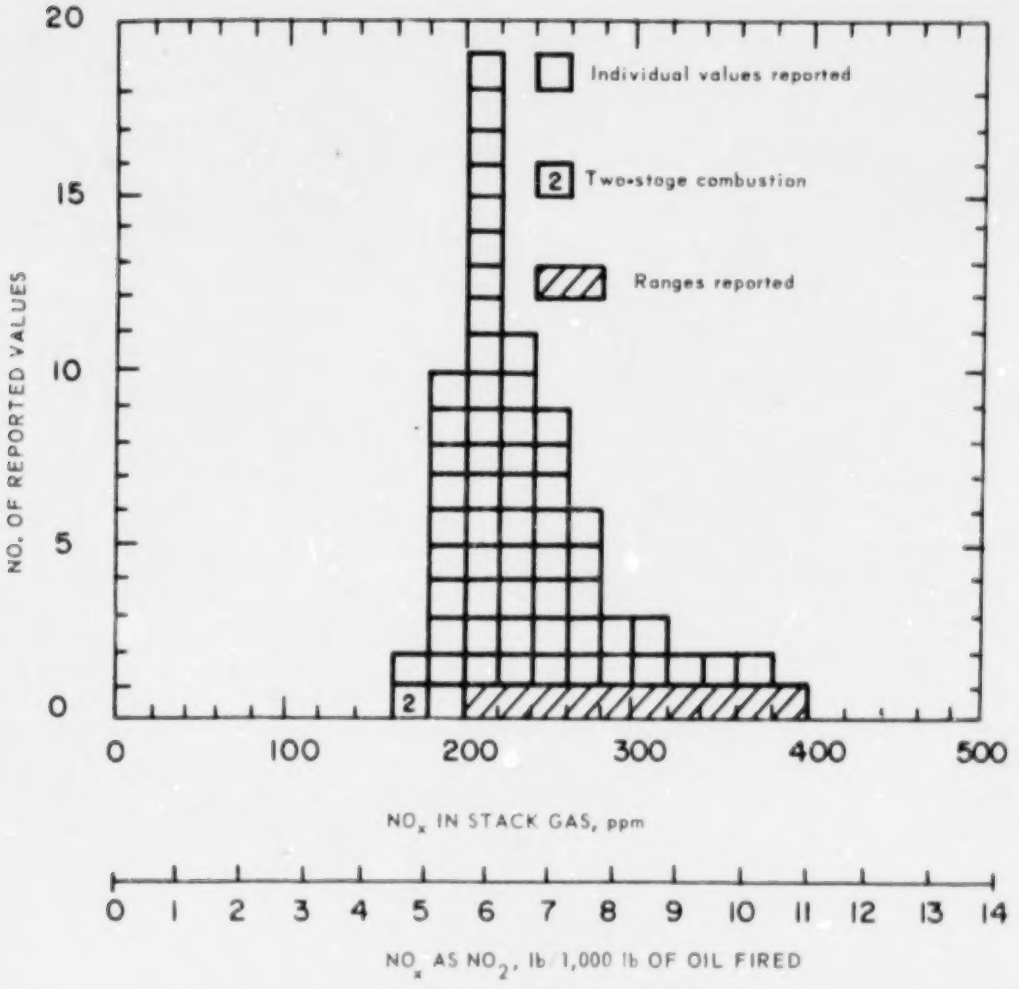

Figure 3. NO_x emissions from large, tangentially fired units.

The most extensive NO_X study was done in Los Angeles County in a joint district, federal, state, and industry project.[19] In this study, the effects of many variables were studied. Results from this project showed a normal range of 275- to 600-ppm NO_X at stack conditions on 63 large sources. (This included 130 tests comprising 554 stack samples.) The average emission rate was 0.78 pound of NO_X per 10^6 Btu, or 14.2 pounds of NO_X per 1,000 pounds of oil fired, calculated on the basis of 18,300 Btu per pound of oil fired. Other studies showed similar results.

All the data collected for NO_X emissions for units, other than tangentially fired, are shown in Figure 4. These data show an extreme range of 0 to 1,020 ppm. The normal range is 300 to 700 ppm, and the most commonly reported values are between 460- and 480-ppm NO_X.

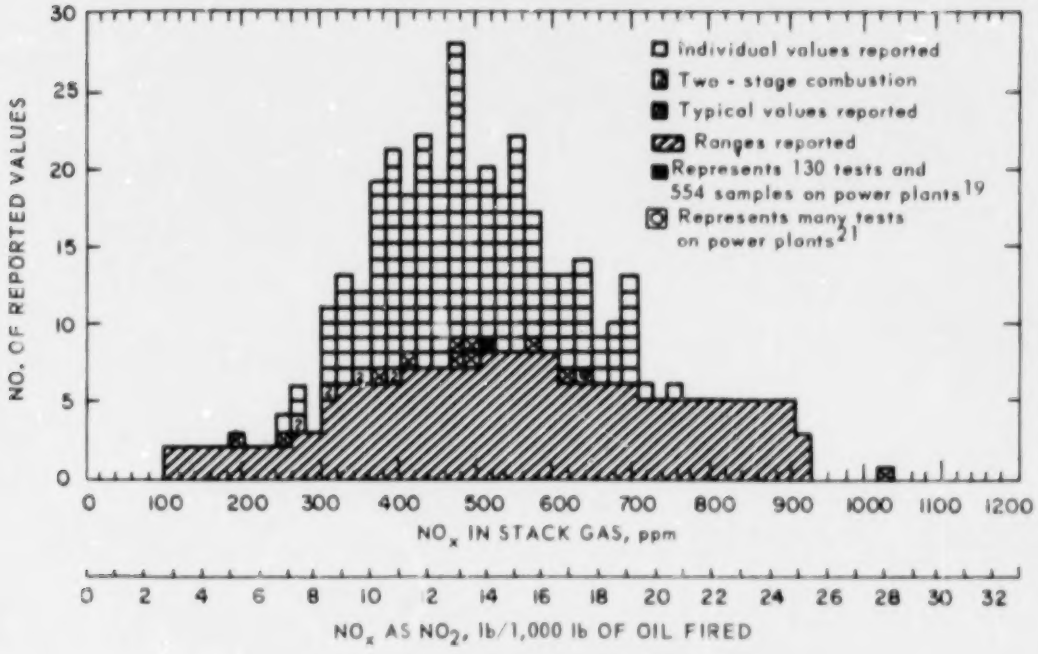
NO. OF REPORTED VALUES
30
25
20
15
10
5
0
Individual values reported
Two - stage combustion
Typical values reported
Ranges reported
Represents 130 tests and 554 samples on power plants[19]
Represents many tests on power plants[21]
0 100 200 300 400 500 600 700 800 900 1000 1100 1200
NOx IN STACK GAS, ppm
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32
NOx AS NO2, lb/1,000 lb OF OIL FIRED

Figure 4. NO_x emissions from large, horizontally fired units.

VARIABLES AFFECTING EMISSIONS

Firing Rate

One author [22] showed that the NO_X emissions varied with the firing rate. His equation may be written as:

$$\text{lb } NO_X/\text{hr} = \left[\frac{X\,(C)}{213}\right]^{1.18} \qquad (2)$$

where X is the firing rate in pounds of oil per hour, C is the percent of carbon in the oil, and NO_X is nitrogen oxides as NO_2. Since oil usually contains about 86 percent carbon, the equation could read:

$$\text{lb } NO_X/\text{hr} = \left[\frac{X}{248}\right]^{1.18} \qquad (3)$$

Data for horizontally fired units conformed to this equation rather closely.

Two-Stage Combustion

Two-stage combustion reduces NO_x emissions. In two-stage combustion, as in other types of combustion, normally 115 to 130 percent of the theoretical air is necessary for good combustion, but only 90 to 95 percent is introduced through the burners with the fuel. The remainder of the necessary combustion air is introduced through auxiliary air ports in the walls of the firebox.[17, 19, 23] One author found that this method of combustion reduced the NO_x concentration by 27 to 47 percent in a horizontally fired unit.[24] Other studies showed that, under normal conditions, in a horizontally fired unit, the average NO_x concentration was reduced by 45 percent.[19, 23] One author who reported data for two-stage combustion in a tangentially fired unit indicated a reduction of 22 percent in NO_x concentrations.[23] In two-stage combustion, the limited oxygen supply near the burner probably inhibits the formation of NO_x.

Load Factor

Large boilers often have a power demand fluctuation. They normally run at about 85 percent of their designed load, which provides a reserve for peak power demand. Several studies indicated an average NO_x decrease from 0.6 to 0.9 percent per 1 percent load decrease below a 70 percent load; and an average NO_x increase from 0.6 to 1.1 percent per 1 percent load increase above a 70 percent load.[19, 25] The increase in NO_x concentration is caused by the increased flame temperature at the higher firing rate.

Excess Air

In electric power plants, the amount of excess air used in the combustion of oil may vary from 8 to 30 percent, in a given plant. The amount of excess air used in large modern plants is about 16 to 20 percent, equivalent to approximately 14 percent CO_2 concentration in the stack gas. This concentration varies with fuel composition and burner design. One author reported on a tangentially fired unit that emitted 13 percent CO_2 and 258-ppm NO_x (corrected to 12 percent CO_2). A linear relationship was established indicating that, as the CO_2 concentration was increased by 1.6 percent (decrease in excess air), the NO_x concentration was reduced by 29 percent. This is equivalent to an 18 percent decrease in NO_x per 1 percent increase in CO_2.[14]

The same author reported on a horizontally fired unit that emitted 13.6 percent CO_2 and 700-ppm NO_x (corrected to 12 percent CO_2). An approximate linear relationship was established

indicating that, as the CO_2 concentration was increased by 0.9 percent, the NO_x concentration was reduced by 32 percent. This is equivalent to a 35 percent decrease in NO_x per 1 percent increase in CO_2. [14]

The joint project conducted in Los Angeles County investigated the relationship of excess air to NO_x formation. This relationship is shown, on the basis of CO_2 concentration, in Figure 5. [19] The NO_x concentration increases with a decrease in CO_2 concentration* because NO_x formation is promoted by surplus oxygen.

Windbox Pressure

The plenum chamber, through which the supply of combustion air is provided to all burners, is the "windbox." Air pressure in the windbox is controlled by opening or closing the air registers. The air registers regulate the flow of air in the windbox in much the same manner as an air damper regulates the flow of hot air in domestic heating units. In one study it was found that the NO_x concentration in the stack gas was decreased considerably when the windbox pressure was increased by 1 inch of water. [19]

Flue Gas Recirculation

Some plants permit a portion of the flue gas to be recycled through the firebox. One author found an average NO_x reduction of 1.3 percent per 1 percent flue gas recycled in a tangentially fired unit. [14] In another study it was found that NO_x was reduced approximately 2.5 percent per 1 percent increase in the opening of the recirculating fan damper. [19] Since recirculating the flue gas reduced the oxygen concentration and flame temperature in the firebox, the amount of NO_x formed was also reduced.

Fuel Pressure and Temperature

One study revealed that, when the fuel feed rate was kept constant and the pressure of the fuel oil was increased, either by decreasing the size of the burner orifices or by decreasing the number of burners for the same fuel rate, NO_x concentration was decreased. The study showed an average decrease of 0.17 percent NO_x per one-psi increase in fuel pressure, when smaller orifice tips were used, [19] but these tips do not last or stay clean as well as larger tips. [14] The study also showed that, when the number of burners in a firebox was increased from the normal 12 to 14, resulting in a 50-psi decrease in fuel pressure, NO_x

*Increase in excess air.

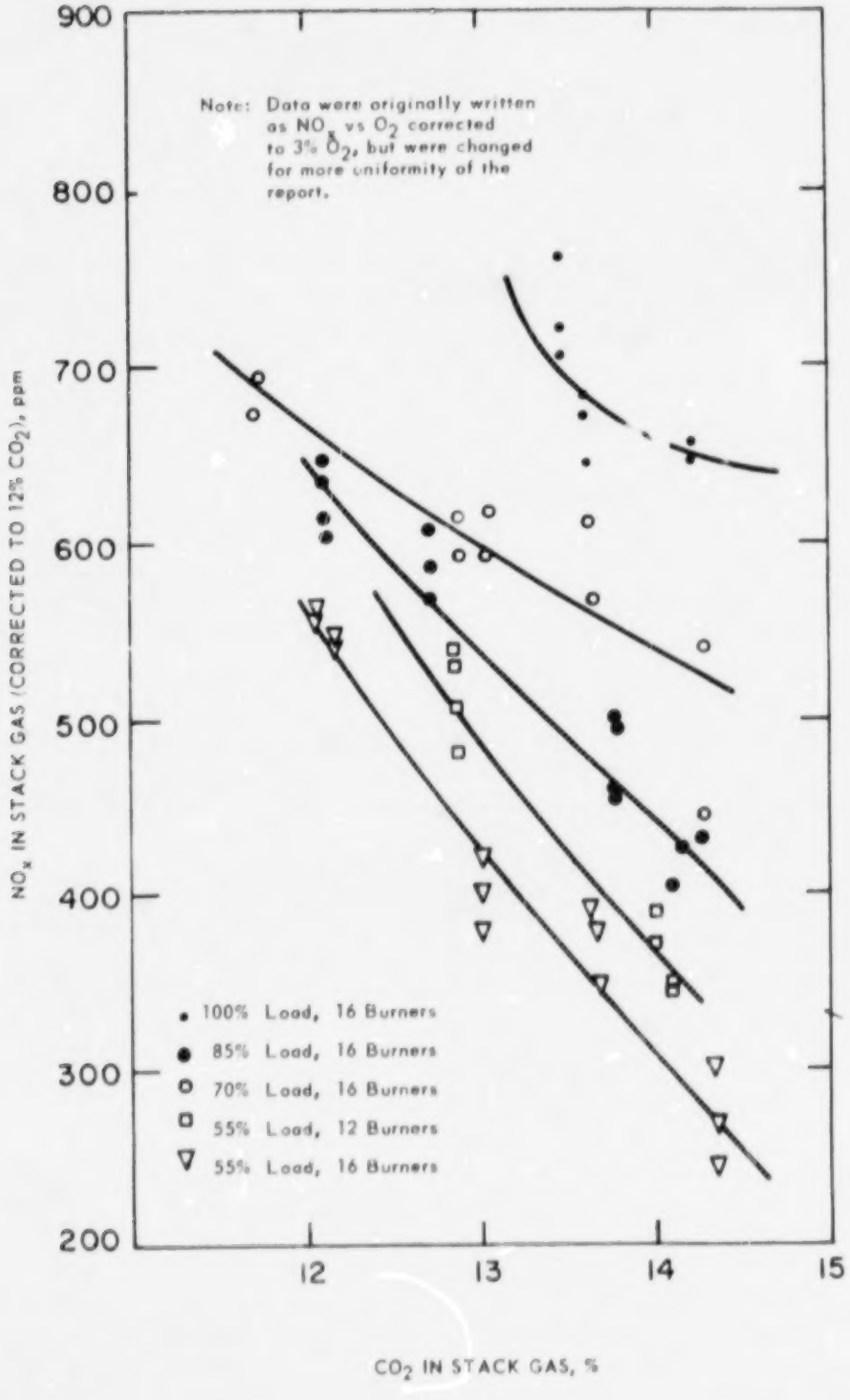

Figure 5. Effect of excess air on emissions of nitrogen oxides from a large unit (Reference 19).

concentration increased 15 percent. When the number of burners was decreased from 12 to 10, resulting in a 100-psi increase in fuel pressure, NO_x concentration decreased 4 percent. [19]

One author found that oil temperature had a small effect on NO_x concentration. His data showed an average of 0.3 percent decrease in NO_x per ^{o}F increase in oil temperature in the range of 207 to 277^{o}F. [14]

Other Variables

NO_x production increases if deposits on boiler tubes are not removed frequently by lancing or by other means. [14, 19] Cleaning the tubes increases heat transfer rates, which might be followed by a reduction in the flame temperature and in NO_x emissions for a given load.

Approach-cone vanes direct the air flow either through or around the burner to the flame to promote efficient combustion. One author found that, by removing the approach-cone vanes from the burners and operating with the air registers wide open, NO_x concentration was reduced 16 percent. [24] This may have been a peculiarity of a specific firebox design.

Sulfur Dioxide (SO_2)

THEORETICAL CONSIDERATIONS

Oil contains many complex organic forms of sulfur, in concentrations ranging from a trace to more than 5 percent by weight. During the combustion of oil, the sulfur in the oil is oxidized to sulfur dioxide (SO_2) in much the same way as carbon is oxidized to carbon dioxide (CO_2). In other words, the oxidation is virtually complete. The SO_2 may react with more oxygen, however, forming sulfur trioxide (SO_3) or sulfate radicals in a complex equilibrium similar to those of the NO_x compounds. This means that not all the sulfur in the oil is emitted as SO_2. The variables controlling the SO_2 emissions are those controlling the formation of SO_3 and metallic sulfates. [7, 26, 27]

The amount of sulfur emitted as SO_2 may be inferred from a material balance. Fly ash contains around 10 percent sulfur, and oil contains around 0.1 percent ash. Thus, about 1 percent of the sulfur in the oil ends up in the fly ash. Sulfur emitted as SO_3 is probably about 1 percent of the sulfur in the oil. Thus, 98 percent of the sulfur in the oil is probably emitted as SO_2.

EMISSION RATES

The data collected on sulfur emissions are presented in Figure 6. The extreme range is from 12 to more than 100 percent of the sulfur in the fuel emitted as SO_2. The normal range is 85 to 100 percent. The most common value is 100 percent. The 100 percent value is questionable as are those values above 100 percent. One of the values plotted at 100 percent or greater represents a calculated value of approximately 120 percent; this impossibility indicates inaccurate sampling and analyzing practices. It would appear from the data and the material balance that the SO_2 emitted in the flue gas represents about 98 percent of the sulfur in the oil.

Sulfur Trioxide (SO_3)

THEORETICAL CONSIDERATIONS

Theoretical equilibrium considerations for the reaction

$$2\ SO_2 + O_2 \rightleftharpoons 2\ SO_3 \qquad (4)$$

indicate a tendency toward SO_3 formation as the temperature of the combustion gas stream becomes increasingly lower than the flame temperature. Catalytic surfaces consisting of iron oxides from the boiler tubes and the vanadium- and iron-bearing ash deposits are present to accelerate the reaction. This reaction is similar to that used in producing SO_3 in a contact sulfuric acid plant; in a combustion chamber, however, there is less catalyst and contact time. [7, 26]

As the products of combustion travel toward the stack exit, and as heat is transferred to the boiler, preheater, and economizer, the temperature of the gases is reduced. If the SO_3 comes in contact with surfaces below the dew point of the gas, the SO_3 combines with water vapor to produce sulfuric acid. The sulfuric acid reacts in turn to produce metallic sulfates on the surface that it contacts, which reduces the SO_3 concentration. The SO_3 markedly increases the dew point of the flue gases to about 300°F. This high dew point of the exhaust gases may result in corrosion of the boiler and stack, and in formation of acidic smuts, as discussed in a previous section. [26, 28, 29, 30, 31, 32, 33]

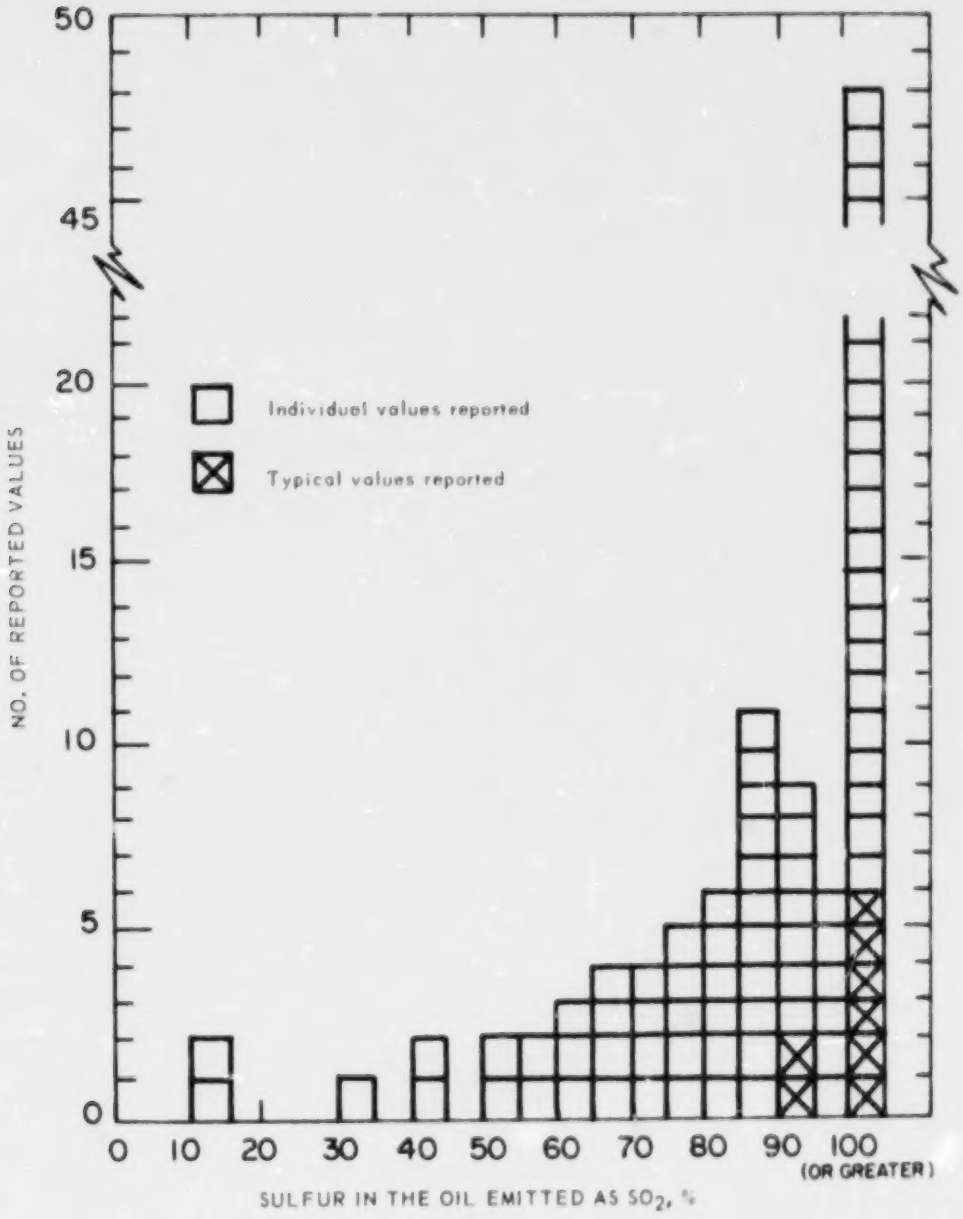

Figure 6. Percent of sulfur in the oil emitted as SO_2 from large units.

EMISSION RATES

The emission of SO_3 to the atmosphere does not appear to be a function of the percent sulfur in the oil only, as does SO_2 emission. To illustrate this, the concentration of SO_3 in the stack gas is plotted against the sulfur content of oil (Figure 7). Lines are arbitrarily drawn to represent 0.4, 1.2, and 2.5 percent of the sulfur in the oil emitted as SO_3. These lines show the wide range of the part of the sulfur in the oil emitted as SO_3. The majority of the data indicate that there is more than 6-ppm and less than 25-ppm SO_3 in the stack gas. For this reason, the SO_3 emission data are represented by two histograms. Figure 8 shows the percent sulfur in the oil emitted as SO_3 and Figure 9 shows the concentration of SO_3 in the stack. Values in Figure 9 are not correlated with the sulfur content of the oil. The ranges found in the literature are as follows (S is the percent sulfur in the oil, by weight):

Range	Reference
90% S converted to SO_2 and 1 to 5% SO_2 converted to SO_3	15
100% S converted to SO_2 and 1 to 2% SO_2 converted to SO_3	16
1 to 5% S converted to SO_3	18
1 to 2.5 lb SO_3/1,000 lb oil, for oil with S of 1.5%	20

Figure 8 shows an extreme range of 0.25 to 11.5 percent of the sulfur in the oil emitted as SO_3. The normal range varies from 0.25 to 2.75 percent, and the most common value is between 1.0 and 1.25 percent of the sulfur in the oil emitted as SO_3. Figure 9 shows that stack concentration varies from 0 to 76 ppm. The normal range varies between 6 and 24 ppm. The most common are between 14- and 22-ppm SO_3.

When the gases leave the stack, they are cooled below the dew point, causing much of the SO_3 to combine with water vapor in the surrounding gas stream, sometimes producing a visible plume. One author reported a visible plume at 3-ppm and a conspicuous plume at 15-ppm SO_3. [17, 18] The particle size of sulfuric acid mist varies from 0.5 to 6 microns, depending upon the amount of water vapor present. [34]

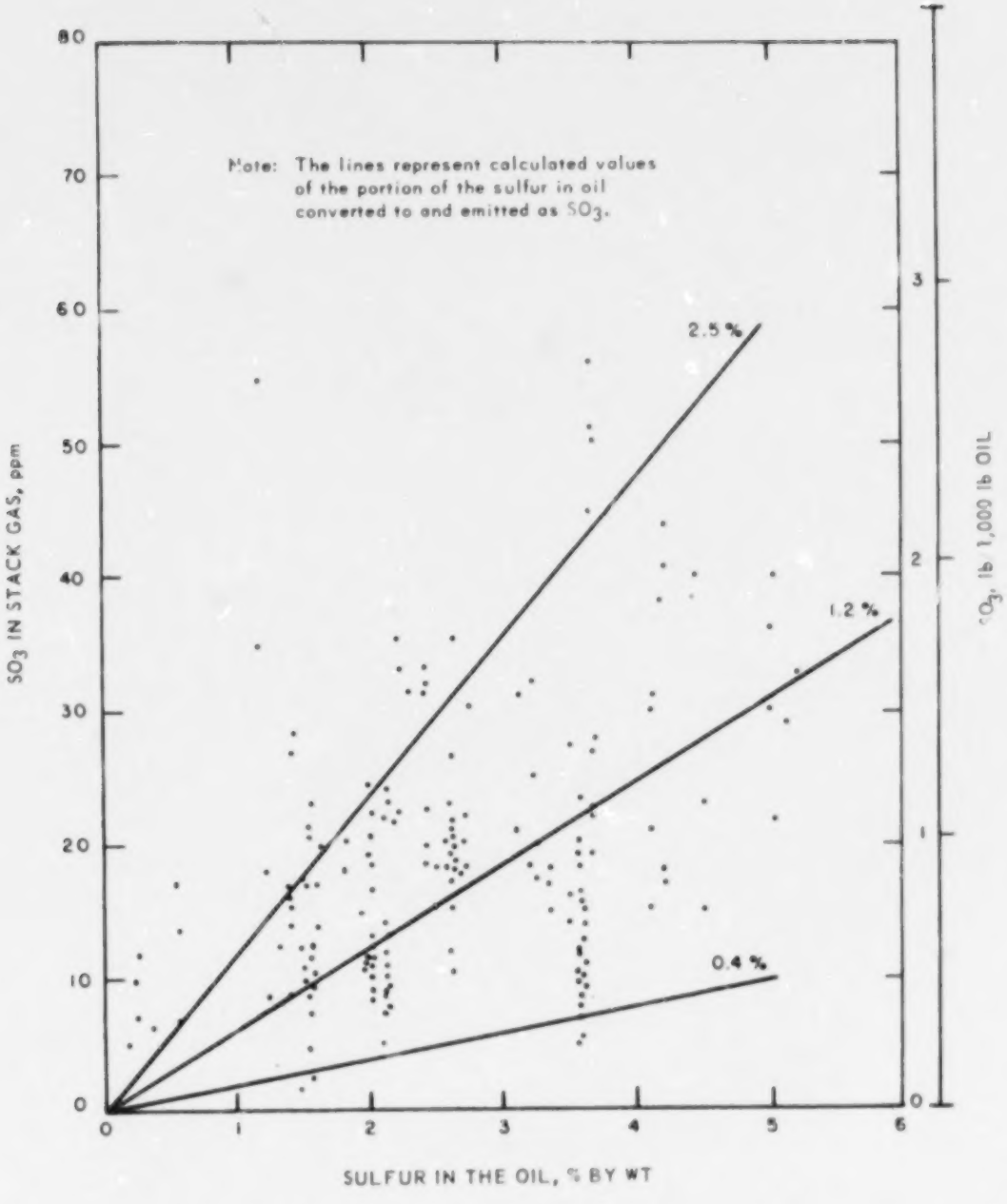

Figure 7. Relationship between SO_3 emission and sulfur in oil for large units.

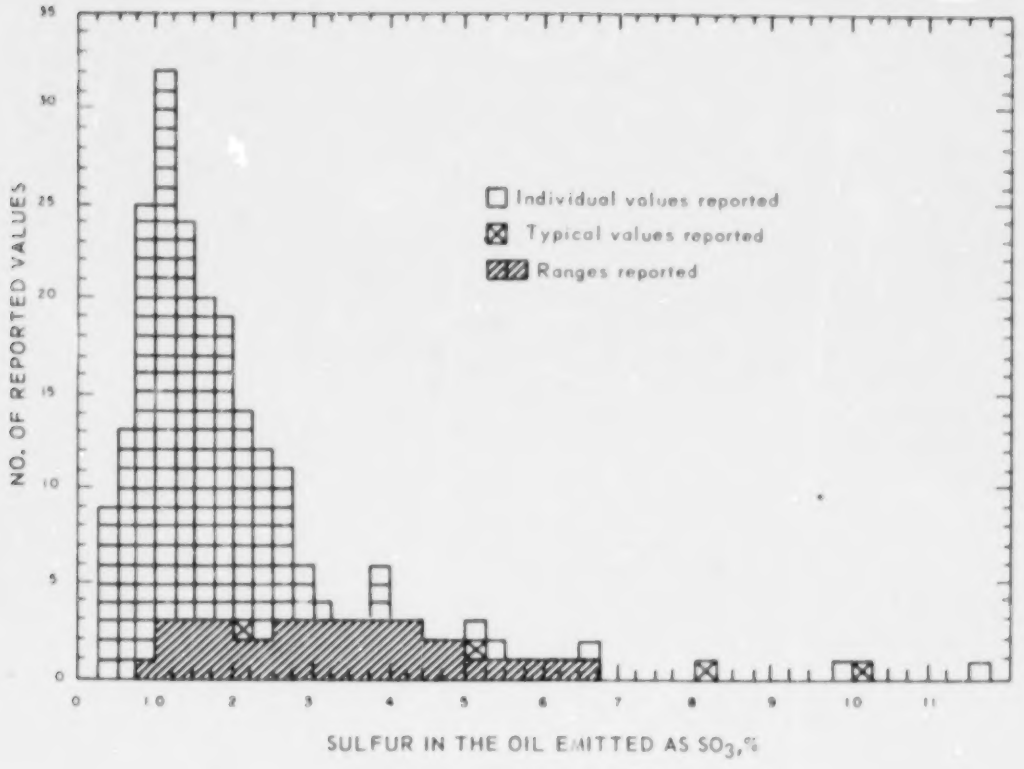

Figure 8. Percent of sulfur in the oil emitted as SO_3 from large units.

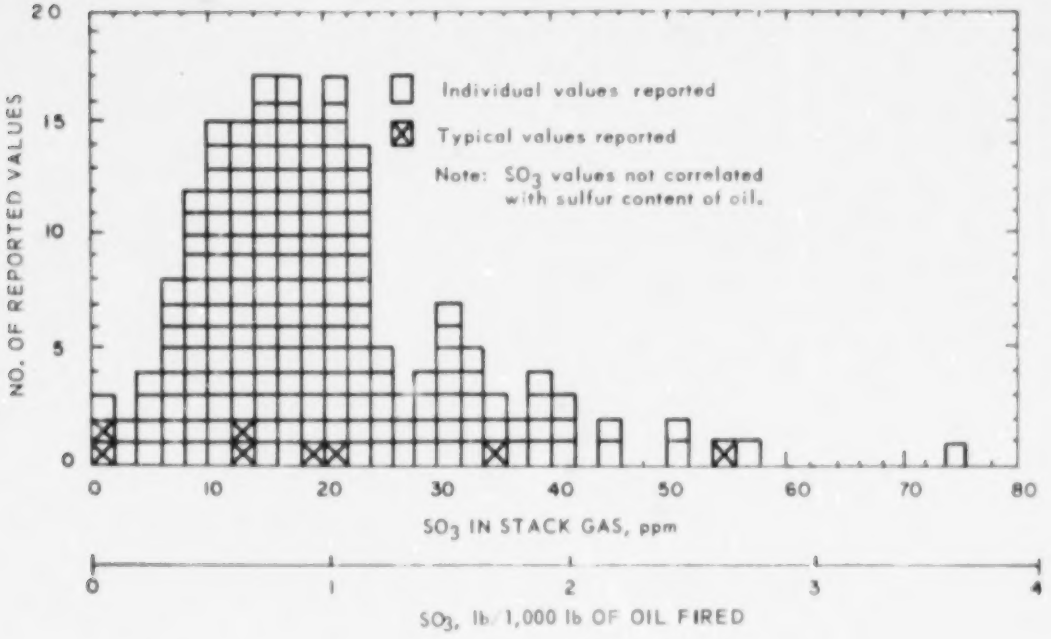
NO. OF REPORTED VALUES
Individual values reported
Typical values reported
Note: SO_3 values not correlated with sulfur content of oil.
SO_3 IN STACK GAS, ppm
SO_3, lb/1,000 lb OF OIL FIRED

Figure 9. Concentration of SO_3 in stack gases of large units.

VARIABLES AFFECTING EMISSIONS

One author found that variation of flame temperature affected SO_3 concentrations in the stack gas. The experiment was done in a pilot plant study and not with actual large furnaces or power plants. A plot of SO_3 content (ppm) versus the flame temperature is shown in Figure 10. [35] This author also indicated that the percent sulfur in the fuel converted to SO_3 decreased with an increase in the percent CO_2 in the stack gas. These data do not agree, however, with other data collected for this report.

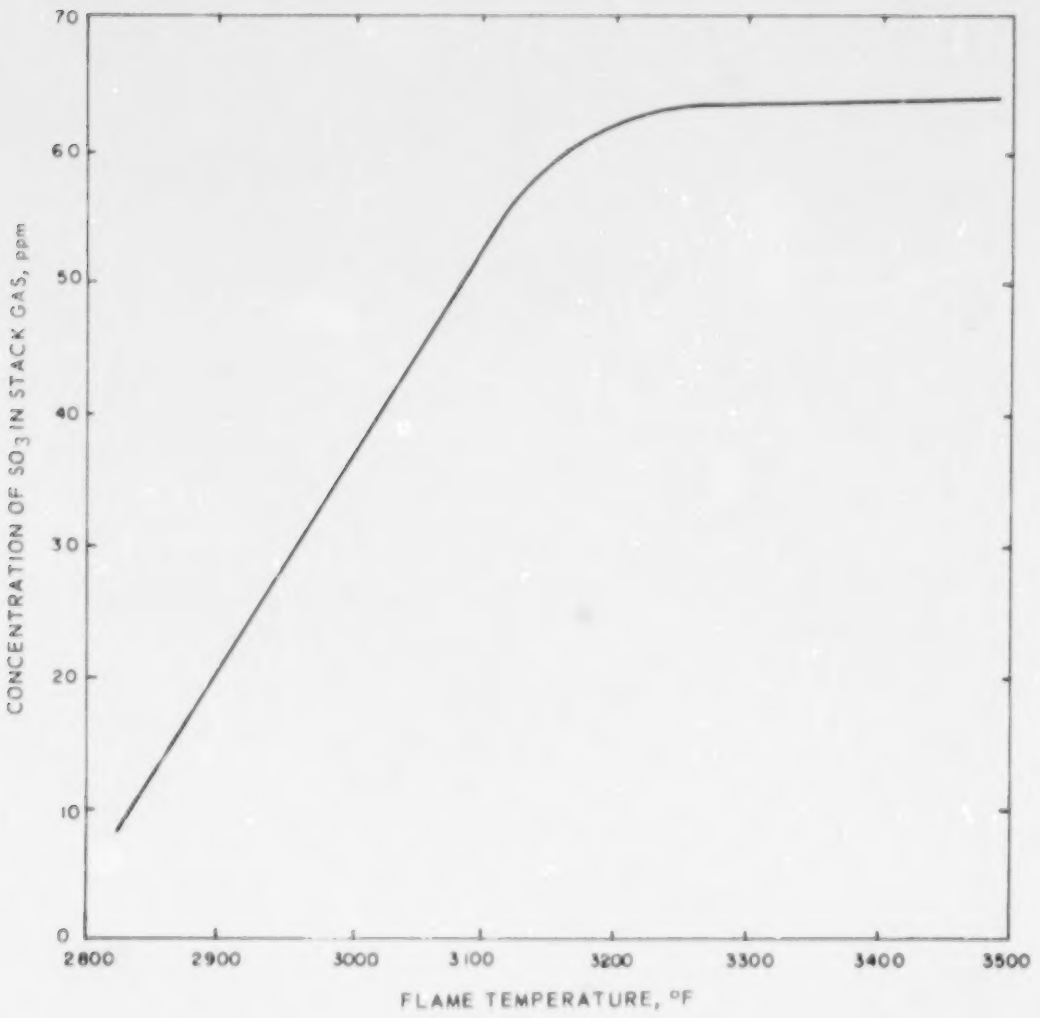

Figure 10. Effect of flame temperature on SO_3 emission (Reference 35).

Other factors that may have a small effect on SO_3 emission are boiler load, fuel pressure, excess air, and percent ash in the fuel. [7, 26, 29, 30, 31, 32, 33, 35, 36, 37] These variables seem to have little significance in the formation of SO_3, however.

Other Gaseous Emissions

Large power plants are usually efficient operations, and therefore, should not emit unburned or partially burned hydrocarbons in significant quantities. Several references, however, have given values for emission of various organic compounds or groups of organic compounds. Since investigators have not reported the organic compounds in a consistent manner, e.g., hydrocarbons measured as hexane, no comparison of the results is possible. Table 10 lists organic compounds found in emissions from large units, as reported by several investigators. Table 10 also shows some values for inorganic gases.

Particulate Emissions

EMISSION RATES

The particulate loading of stack gases depends primarily upon the efficiency of combustion and the rate of build-up of boiler deposits. The data do not follow any trend when the percent ash in the oil is plotted against stack loadings. When oil containing one pound of ash is introduced into a large boiler, as little as one-half pound or as much as 10 pounds of particulates could be emitted. This emission may result from a build-up or detachment of boiler deposits, carbon in the fly ash, H_2SO_4 reacting with the boiler or stack, or from a combination of these factors.

Particulate loading ranges cited in the literature are 0.02 to 0.04 grains per cubic foot [15] and 1 to 5 pounds per 1,000 pounds of oil fired (0.0325 to 0.1625 gr/scf, calculated). The latter value is for low-pressure atomization. The loading was reduced by two-thirds when high-pressure atomizing was used. [20] All the literature values for particulate matter are represented in Figure 11. This figure shows an extreme range between 0.005 and 0.205 gr/scf. The normal range is between 0.025 and 0.060 gr/scf. The most commonly reported values are between 0.030 and 0.035 gr/scf.

Table 10. MISCELLANEOUS GASEOUS EMISSIONS FROM LARGE SOURCES
(Reported in lb/1,000 lb oil fired, unless otherwise stated)

CO	Hydrocarbons as hexane	Other hydrocarbons as propane	Hydrocarbons, general	Organics	Other organics (such as chlorinated alcohols, hydrocarbons)	Organic acids as acetic	Aldehydes as formaldehyde	Aldehydes	Aldehydes and ketones	Acetylene	Ethylene	H_2S	HCN	HCl	NH_3	References
--[a]	--	--	--	5[b]	--	15[b]	1	--	--	--	-	< 1	< 1	< 1	1	[38] Literature search
0.0051	--	--	0.097	--	0.326	--	--	--	0.071	--	-	--	--	--	--	[21] Many tests on power plants
0	--	13 ppm c, d	--	--	--	--	--	--	--	0	0	--	--	--	--	[39] Using infrared techniques, also got 0 ppm NO_x
--	--	--	--	5[b]	--	15[b]	--	1.2	--	--	-	--	--	--	--	[40] Typical
100 ppm or greater for poor combustion [d, e]	--	--	--	--	--	--	--	--	--	--	-	--	--	--	--	[1] Typical
100 ppm or less for poor combustion[d, e]	--	--	--	--	--	--	--	--	--	--	-	--	--	--	--	[17] Typical
--	0.28 0.095	--	--	--	--	0.235 0.41	nil 0.65	--	--	nil 0.03	-	--	--	--	--	[41] Two tests

[a] -- no data reported.

[b] Numbers are believed too large for good combustion.

[c] 13 ppm propane ≈ 0.34 lb/1,000 lb oil fired.

[d] CO_2 correction not indicated in reference.

[e] 100 ppm CO at 12% CO_2 ≈ 1.66 lb/1,000 lb oil fired.

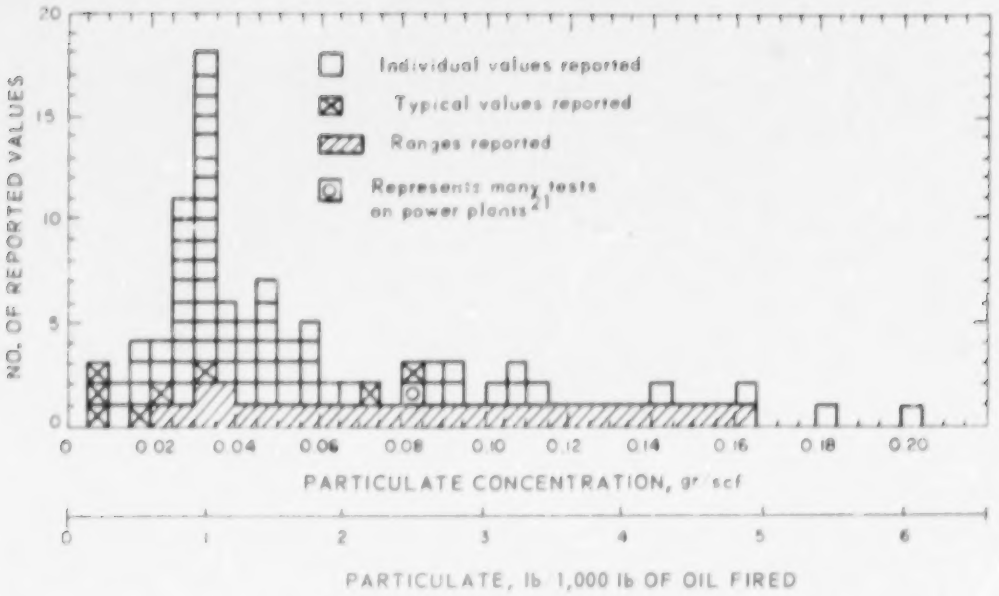

Figure 11. Particulate loading in stacks of large units.

PARTICLE SIZE

The size distribution depends upon the degree of atomization of the oil, the efficiency of mixing, the number of collisions between fly ash particles, the flame temperature, the design of the firebox, and the flue gas path through the boiler to the stack.[7] The lighter particles usually contain less carbon and are smaller in size. The literature shows an assortment of sizes (Table 11).

The larger particles are skeletons of burned-out fuel particles called cenospheres, which are hollow, black, coke-like spherical particles.[46] The smaller particles formed by the condensation of vapors are of regular shape and usually have a maximum dimension of about 0.01 micron.[7] Good atomization usually reduces the number of cenospheres.

Table 11. SIZE OF PARTICULATES EMITTED FROM LARGE UNITS

Size and weight percent, as reported	Reference
0.4μ	42
0.4μ (estimate) or 90% less than 0.5μ	1
95% less than 0.5μ	43
1μ or less	44 & 7
less than 1μ to 40μ	16
47% less than 3μ 53%, 3 to 4μ	45
53% greater than 4μ [a]	46
95%, 10 to 1,000μ [a]	20

Method of collection	Percent by number 0-1μ	1-2μ	2-5μ	5+μ	Largest size	Remarks	
Millipore	48.4	28.8	16.7	6.1	15μ	Most particles black in color; a few 80μ in size	47
Millipore	64.2	18.8	10.0	7.0	15μ		
Millipore	93.5	3.2	2.0	1.3	20μ	Most particles light in color	
Glass cloth	94.8	2.2	1.5	1.0	20μ		

[a] Carbon particles only.

CHEMICAL COMPOSITION AND DESCRIPTION

No general statement can be made on the highly variable composition of fly ash from oil combustion. The probable constituents of fly ash that may be found in flue gas are as follows:

Al_2O_3, $Al_2(SO_4)_3$, CaO, $CaSO_4$, Fe_2O_3, $Fe_2(SO_4)_3$, MgO, $MgSO_4$, NiO, $NiSC_4$, SiO_2, Na_2SO_4, $NaHSO_4$, $Na_2S_2O_7$, V_2O_3, V_2O_4, V_2O_5, ZnO, $ZnSO_4$, $Na_2O{\cdot}V_2O_5$, $2Na_2O{\cdot}V_2O_5$, $3Na_2O{\cdot}V_2O_5$, $2NiO{\cdot}V_2O_5$, $3NiO{\cdot}V_2O_5$, $Fe_2O_3{\cdot}V_2O_5$, $Fe_2O_3{\cdot}2V_2O_5$, $Na_2O{\cdot}V_2O_4{\cdot}5V_2O_5$ and, $5Na_2O{\cdot}V_2O_4{\cdot}11V_2O_5$.[48] The average compositions of ash found in various oils before firing are given in Table 9.

The composition of the fly ash changes as the gas leaves the firebox and travels through the boiler and the internal parts of the power plant. As the gas cools, some of the fly ash condenses and solidifies, some reacts with the boiler and stack, and some is deposited within the unit. The fly ash composition varies from plant to plant and from oil to oil. Table 12 shows analyses of fly ash from a plant using residual oil.[46] Vanadium is usually present in the fly ash and has been considered for use an an indicator of the presence of fly ash from oil-fired units. Ranges

reported for percent combustibles in the fly ash are 50 to 75 percent; [20] 30 to 40 percent (but up to 94 percent); [46] and, in 31 tests in one plant, a variation from 61.1 to 95.2 percent. [23] The amount of combustibles in fly ash decreases with increased atomization pressure and flame temperature. [49] A decrease in the percent combustibles in fly ash should accompany a decrease in stack loading; not enough data are available, however, to make a definite statement.

Recently, much attention has been focused on the emission of potentially carcinogenic substances from various operations. These substances are usually polynuclear hydrocarbons, of which 3,4-benzpyrene is the most studied example. Only one author has reported information on emission of these materials from oil-burning units. Gurinov, a Russian investigator, found 3,4-benzpyrene in concentrations of 0.01 percent of the soot emitted from the combustion of petroleum introduced in a furnace through a spray burner. [70] Some as yet unpublished sampling data indicate that about 0.004 percent of the soot is 3,4-benzpyrene when oil is burned by means of an air-atomized oil burner. [45] These limited data indicate that about 0.04 to 0.10 pounds of 3,4-benzpyrene is emitted per million pounds of oil burned.

Other properties of the fly ash given in the literature are an initial pH of 3; [20] 17 to 25 percent SO_3 (which includes H_2SO_4 droplets); [46] and a specific gravity of 2.5. [20] The amount of soluble solids reported in one reference ranged from 30 to 60 percent. [19] This range of soluble solids and other values from references (50) and (42) are represented in Figure 12. The values range between 1.3 and 68 percent soluble solids.

VARIABLES AFFECTING EMISSIONS

Efficiency of Combustion

Poor mixing, turbulence of the air and oil, low flame temperatures, and short residence time in the combustion zone cause larger particles, higher combustible content, and higher particulate loadings. [12]

Table 12. ELEMENTAL ANALYSES OF TOTAL PARTICULATES (Reference 46)
(Data in percent)

Elements	Test A Total solids from burning PS[a] 400 oil (collected in a laboratory electrical precipitator at 230°F)	Test B Total solids from burning 4° API oil (collected in a glass filter sock at 300°F)
Carbon	58.1[b]	18.1[b]
Ether, soluble	2.3	4.4
Hydrogen	---	---
Ash (900°C)	17.4	51.2
Sulfates as SO_3 (incl H_2SO_4)	17.5	25.0
Chlorides as Cl	---	.5
Nitrogen as NO_3	---	.3
Iron as Fe_2O_3	3.1	3.7
Chromium as CrO_2	.06	.3
Nickel as NiO	1.8	13.2
Vanadium as V_2O_3	2.5	4.7
Cobalt as Co_2O_3	.08	.3
Silicon as SiO_2	.6	9.7
Aluminum as Al_2O_3	1.6	14.9
Barium as BaO	.4	.1
Magnesium as MgO	.2	.7
Lead as PbO	.1	.2
Calcium as CaO	.2	.4
Sodium as Na_2O	.9	3.0
Copper as CuO	.01	.25
Titanium as TiO_2	---	.004
Molybdenum as MoO_2	.02	.03
Boron as B_2O_3	.01	.1
Manganese as MnO_2	.04	.04
Zinc as ZnO	---	.08
Phosphorus as P_2O_5	.9	---
Strontium as SrO	.04	---
Titanium as TiO	.03	---

[a] Pacific Standard.

[b] Value probably includes minor amount of hydrogen.

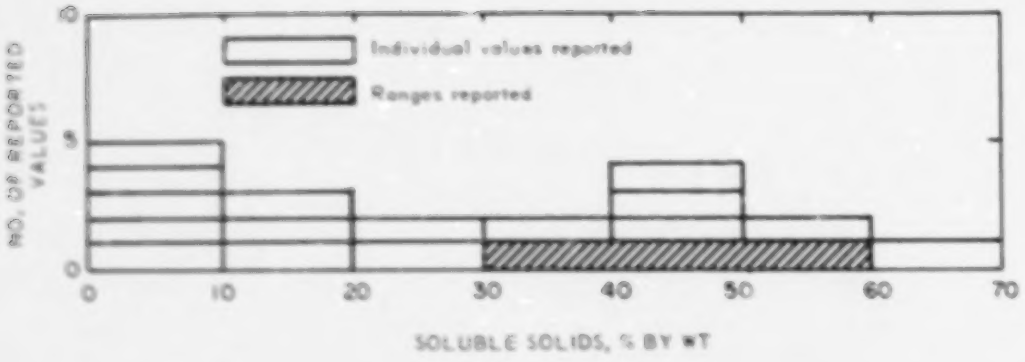

Figure 12. Percent soluble solids in fly ash from large units.

Atomization

The degree of atomization has an important effect on particulate emissions. Low-pressure atomization produces larger fly ash particles and a higher particulate loading. [49] High-pressure atomization (400 psig or greater) produces smaller particles, fewer cenospheres, and lower particulate loadings. [20]

Oil viscosity has a major effect on atomization. Oil viscosity is a function of temperature, for a given oil. In two experiments on a 186-megawatt plant, seven tests showed that increasing the oil temperature (which was normally between 230 and 240°F) by approximately 35°F halved the fly ash emission and reduced the combustible portion by 15 to 17 percent. [23]

The size of the burner orifice affects atomization, and thus the particle size and loading. Also, clean burners promote good atomization. [12]

Windbox Air Admittance

Varying the settings on the main and auxiliary air dampers caused pronounced effects on ash emissions in two series of tests on a 186-megawatt plant. In the first series of tests (3 tests), the main dampers were not completely opened, but the auxiliary dampers were opened quickly. This produced large increases in the fly ash loading and combustible content. [23] In the second series of tests (5 tests), a much wider range of damper settings was used. The fly ash loadings did not rise as sharply as under conditions of the first series of tests. The combustible content stayed essentially constant in the second series of tests. [23]

Burner Tilt

One investigator conducted several series of tests involving change in burner tilt, with and without flue gas recirculation. There was very little effect on either the fly ash loading or combustible content of the fly ash when flue gas was not recirculated. When some flue gas was recirculated, however, the combustible content and loading of fly ash tended to reach a maximum with the burner tilted zero degrees from the horizontal. This would indicate that best operation, from the air pollution standpoint, would result with burners inclined either up or down. No conclusion has been reached on the combined effect of burner tilt and flue gas recirculation. [23]

Excess Air

Increasing the amount of excess air usually decreases the fly ash loading and combustible content of the fly ash since more complete combustion results. In a series of four tests it was found that, as the oxygen concentration in the stack gas increased from 2 to 4 percent, the particulate loading decreased from 0.140 to 0.020 gr/scf, respectively. Or stated another way, an increase in the CO_2 content in the stack gas from 13.1 to 14.7 percent resulted in a 7-fold increase in particulate loading. [23]

Flue Gas Recirculation

Fly ash emission increases as more flue gas is recirculated into the firebox. This is owing to a cooling of the flame and of combustion gases. One author found that, when the burners of a 186-megawatt plant were at a zero tilt from the horizontal, and when flue gas recirculation was increased from 0 to 15 percent, the fly ash loading increased 100 percent. The combustible content of the fly ash stayed essentially constant. [23]

Sootblowing

Sootblowing increases the particulate loading in stack gases. One author reported a 1.7-fold increase in particulate loading during sootblowing in one operation and a 3.3-fold increase in another, above normal emissions of 0.11 and 0.039 gr/scf, respectively. [46] Another author found an increase 2.3 times the normal emission of 0.028 gr/scf during sootblowing. [23]

EMISSIONS FROM SMALL INSTALLATIONS

The term "small sources" refers to sources of less than 1,000 hp (equivalent to 34,500-pounds steam production per hour or 2,500 pounds of oil fired per hour). These units are used in domestic heating, commercial heating, and in supplying heat and power to small industrial processes. Because of the smaller sizes of the units, flame temperature is usually lower than in larger sources. In many cases, less attention is given to treatment of fuel and regulation of combustion air for small units than is usually the case for large units. This often results in less efficient combustion in smaller units.

Small units, in general, produce less NO_x and more fly ash and unburned hydrocarbons than the large sources, because of the reduction in flame temperature and in combustion efficiency. Since there is a wide variation in fuels used in the small sources, emissions are reported in pounds per 1,000 pounds of oil fired. Descriptions of emissions and variables affecting emission rates are similar to those for large sources and are covered there.

Oxides of Nitrogen (NO_x)

The literature values for NO_x emitted from small units are considerably less than those for large units. In a joint district, federal, state, and industry project involving measurement of emissions from 530 units producing 500 horsepower or less, an emission factor was established. This factor was 0.49-pounds NO_x per 10^6 Btu, or 9-pounds NO_x per 1,000 pounds of oil fired (calculated on the basis of 18,300-Btu/lb oil). [51] In another program, which included many tests on both large and small sources, a general value of 7.2-pounds NO_x per 1,000 pounds of oil fired was established for small sources. [21] Other general values found in the literature are 13- [44] and 7-pounds NO_x [38] per 1,000 pounds of oil fired. The values reported in the literature range from 0 to 18 pounds per 1,000 pounds of oil fired, and these are shown in Figure 13. The data presentation method used in the figure indicates that the most common value is between 0 and 4. A more reliable average value, however, would be about 9-pounds NO_x per 1,000-pounds oil fired, based on the joint project conducted in Los Angeles County. [51]

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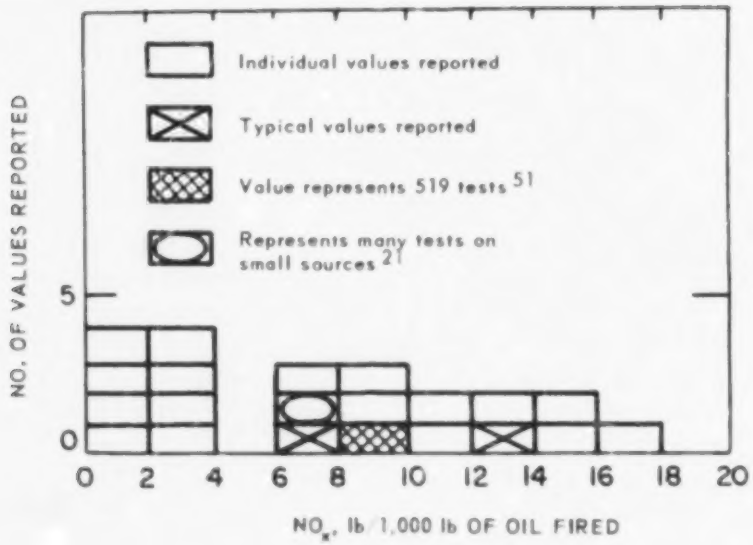
Individual values reported
Typical values reported
Value represents 519 tests [51]
Represents many tests on small sources [21]
NO. OF VALUES REPORTED
5
0
0 2 4 6 8 10 12 14 16 18 20
NO_x, lb/1,000 lb OF OIL FIRED

Figure 13. NO_x emissions from small units.

Sulfur Dioxide (SO_2)

Sulfur dioxide emission data for small units are shown in Figure 14. This distribution of values is similar to that for large sources. The extreme range is 0 to 100 percent of the sulfur in the fuel oil emitted as SO_2. Values up to 254 percent were reported. This is impossible, however, and such values are assumed to be 100 percent. (The error is probably owing to inaccuracies in sampling and analyzing practices.) The normal range is from 70 to 100 percent, and the most common value is 100 percent of the sulfur emitted as SO_2, as it was for the large sources. For reasons discussed previously under large source emissions, 98 percent of the sulfur emitted as SO_2 is considered a more reasonable figure.

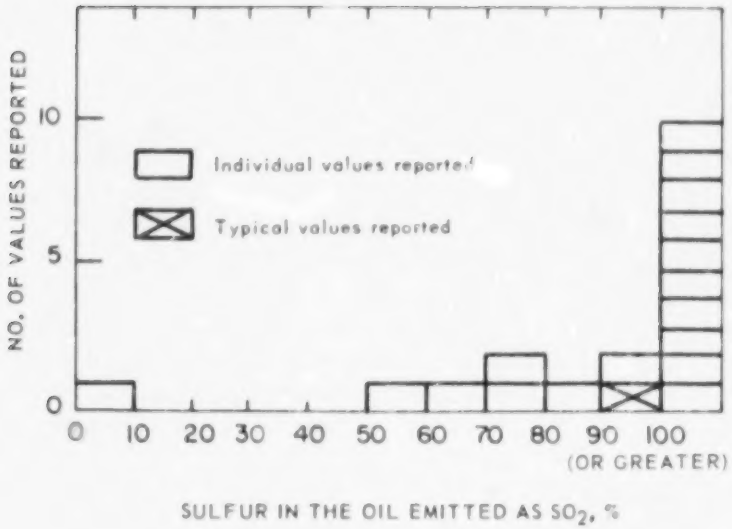

Figure 14. Sulfur dioxide emissions from small units.

Sulfur Trioxide (SO_3)

Values found in the literature for sulfur trioxide emissions are shown in Figure 15. This figure shows an extreme range of 0 to 13.75 percent of sulfur in the fuel oil emitted as SO_3. The normal range is between 0 and 1.25 percent and the most common value is between 0 and 0.25 percent of the sulfur emitted as SO_3. Figure 15 indicates, however, that there are sufficient values reported to support the conclusion that about 1 percent of the sulfur in the oil is emitted as SO_3. This conclusion would be in more general agreement with the SO_3 emission from large sources.

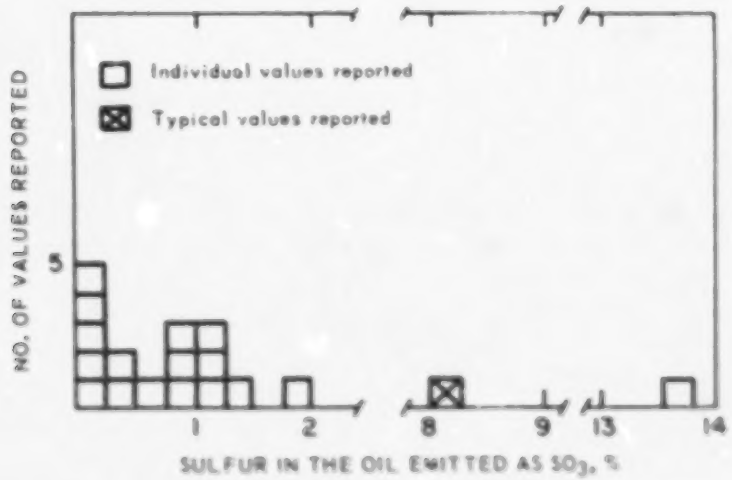

Figure 15. Sulfur trioxide emissions from small units.

Other Gaseous Emissions

Smaller sources tend to emit more organic compounds than larger sources. This is owing to lower flame temperature and lower combustion efficiency in smaller units. Literature values for carbon monoxide are shown in Figure 16 and for aldehydes, as formaldehyde, in Figure 17. The extreme range for CO emissions is 0 to 194 pounds per 1,000 pounds of oil fired. The normal range is between 0 and 1, and the most common values are between 0- and 0.5-pound CO emitted per 1,000-pounds oil fired. The extreme range for the aldehydes, as formaldehyde, is 0 to 3.3 pounds per 1,000 pounds of oil fired. The normal range is 0 to 0.6 pound, and the most common values are between 0.2 and 0.3 pound per 1,000 pounds of oil fired.

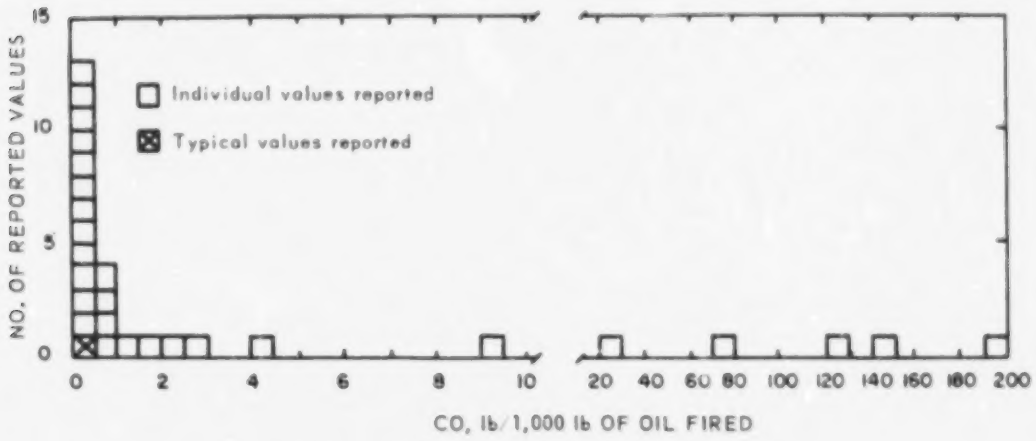

Figure 16. Carbon monoxide emissions from small units.

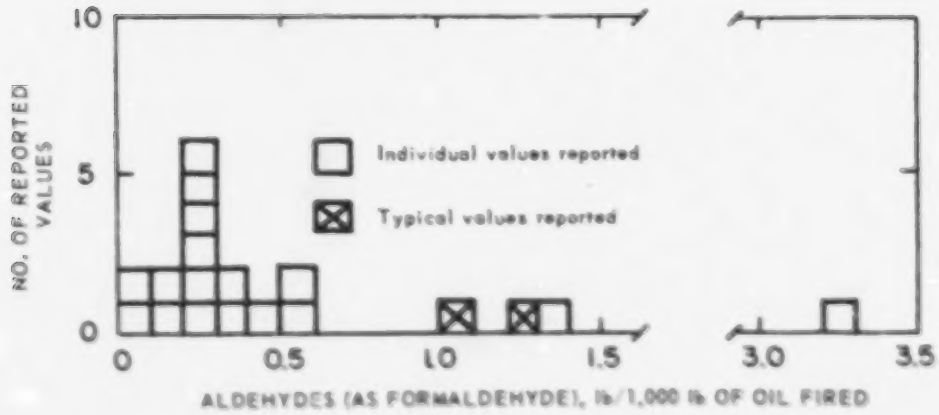

Figure 17. Aldehydes (as formaldehyde) emitted from small sources.

One author reported a variation of hydrogen (H_2) from 0.58 to 0.011 percent in the stack gas when the CO_2 varied from 12.4 to 10.8 percent, respectively. The H_2 increased to 0.215 percent when the CO_2 was reduced to 8.3 percent. The highest H_2 content of 0.58 percent corresponded to a Number 9 Shell smoke number, * which is equivalent to Ringelmann Number 1. Number 8 Shell smoke number has been reported as the beginning of the visible range. [52] Data for other pollutants are listed in Table 10. In addition to these data, another program that included many tests on commercial and domestic sources established the following emissions in pounds per 1,000 pounds of oil fired: hydrocarbons, 0.080; aldehydes and ketones, 0.063; and other organic gases, 0.177. These figures are believed to be the most nearly correct for small sources.

Particulate Emissions

The fly ash loadings for small sources are slightly higher than those for large sources. The data are presented in Figure 18. The extreme range is between 0 and 10 pounds of particulate per 1,000 pounds of oil fired. The normal range is between 1 and 4 pounds of particulate per 1,000 pounds of oil fired, and the most common values are between 1 and 2 pounds of particulate per 1,000 pounds of oil fired.

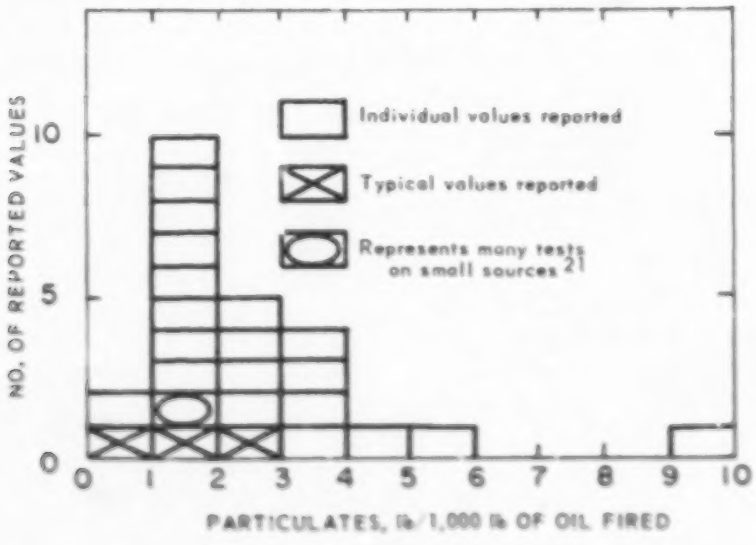
Individual values reported
Typical values reported
Represents many tests on small sources [21]
NO. OF REPORTED VALUES
0
5
10
0 1 2 3 4 5 6 7 8 9 10
PARTICULATES, lb/1,000 lb OF OIL FIRED

Figure 18. Particulate emissions from small sources.

* The Shell smoke number is determined by drawing a sample of flue gas through a filter paper and comparing the stain on the paper to nine standards of approximately equal steps of reflectivity. The shades range from light to dark, the darkest being Number 9, which corresponds to Number 1 Ringelmann. [52]

CONTROL OF EMISSIONS

Oxides of Nitrogen (NO_x)

The formation of nitrogen oxides increases with the flame temperature, the length of time the gases remain in the flame, and the amount of oxygen available. The flame temperature is influenced by many variables; available oxygen is related to the amount of excess air present. The most important factor in reducing NO_x formation is furnace design. Tangential firing and two-stage combustion – either one alone or both in combination – reportedly produce significantly less NO_x than other procedures. By decreasing the flame temperature or available oxygen, the NO_x concentration may be decreased. This decrease may be achieved by reducing the amount of excess air, recirculating combustion gases, or changing burner conditions. These measures may, however, increase particulate loading because of less efficient combustion.

Sulfur Dioxide (SO_2)

Emission of sulfur dioxide is a direct function of the sulfur in the fuel. Emission of sulfur dioxide may be reduced either by using low-sulfur crude oils or by removing the sulfur.

Sulfur Trioxide (SO_3)

Sulfur trioxide formation is initially a function of the SO_2 concentration and temperature (provided there is a catalyst present). As a result of reactions of the SO_3 with other combustion products and with the combustion and heat transfer equipment, however, the SO_3 actually emitted to the atmosphere shows no direct correlation with the sulfur content of the oil. Effective ways of controlling emissions of SO_3 include the use of additives and the use of an electrostatic precipitator in the exit gas stream.

The basic objective of using additives is to reduce boiler deposits and corrosion. The additives are usually added with the fuel or added to the flue gases directly after combustion. These compounds usually react with the SO_3 and tie it up in the form of neutral salts. Some of the more common additives are oxides, carbonates, soaps, and naphthenates of calcium, zinc, magnesium, sodium, and other metals. The additives, by forming sulfate

salts, usually reduce the SO_3 concentration, sometimes up to 50 percent, but increase the particulate loading to 1.5 to 7 times the normal loading. Carbon, pulverized coal, and fly ash from pulverized coal have also been used as additives.[1, 7, 26, 29, 30, 31, 32, 33, 53, 54, 55, 56, 57, 58]

Smoke and Organic Gases

Emission of smoke and organic gases is the result of incomplete or inefficient combustion of the oil. Some of the more common causes of poor combustion are listed in Table 13. By proper adjustment and operation, smoke emission can be eliminated.[12]

Acidic Smuts

Acidic smuts are caused by the flue gas coming in contact with a surface whose temperature is below the dew point of the flue gas. By maintaining surface temperatures and flue gas temperatures above the dew point of the flue gas, these smuts may be prevented. One author insulated the stack of an installation and prevented formation of smuts.[13]

Particulates

Particulate emissions decrease as combustion efficiency increases. Good combustion efficiency is obtained by high flame and firebox temperature, high-pressure atomization, high excess air, and low flue gas recirculation. These measures may, however, increase the NO_x formation. When the particulate emission is decreased by adjustment of some of these variables, the NO_x emission may increase.

Use of collectors, such as multiple cyclones, on oil-fired units is usually limited to periods when sootblowing operations are in progress. Cyclones collect particles of around 10 microns and larger, but they do not efficiently collect particles of 5 microns or less.

The use of electrostatic precipitators is, at present, limited. They are found only in those areas where restrictive legislation requires low particulate loadings and low opacity of stack effluents. Electrostatic precipitators are generally used continuously. They collect nearly all the particulates, including

liquid droplets, such as H_2SO_4. The particulate loading may be decreased 90 percent or more and the SO_3 emission may be decreased by as much as 50 percent of the original concentration when electrostatic precipitators are used. [1, 7, 42, 43, 59, 60, 61, 62]

Table 13. COMMON CAUSES AND RESULTS OF POOR COMBUSTION (Reference 12)

Cause	Result		
	Smoking fire	Carbon formation in the boiler	Pulsating fire
Insufficient air or too much oil (improper air-fuel ratio)	X	X	X
Poor draft	X	Sometimes	X
Excess air (causing white smoke)	X		
Dirty or carbonized burner tip (caused by improper location, insufficient cleaning at regular intervals)	X	X	
Carbonized or damaged atomizing cup (rotary cup)	X	X	
Worn or damaged orifice hole	X	X	
Improper burner adjustment (diffuser plate protruding improper distance)	X	X	Sometimes
Oil pressure to burner too high or too low	X	X	
Oil viscosity too high	X	Sometimes	
Oil viscosity too low (too high fuel oil temperature)		X	X
Forcing burner (especially after initial light-off or when combustion space is relatively cold)	X	X	X
Insufficient atomizing steam	X	X	
Water in fuel oil		X	X
Dirty fuel oil	X	X	X
Fluctuating oil pressure	Intermittent		X
Incorrect furnace construction causing flame and oil impingement		X	
Carbon clinker on furnace floor or walls	X	X	
Incorrect atomizer tip size		X	
Condensate in atomizing steam	X		X
Atomizing steam pressure too high			X
Furnace cone angle too wide			X
Furnace cone angle too narrow (making it necessary to have atomizer in maximum position)		X	X
Atomizer not immediately removed from burner being secured		X	

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APPENDIXES

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS

APPENDIX B. DETAILED DATA ON SMALL SOURCE EMISSIONS

APPENDIX C. METHOD OF REPORTING THE DATA

					"	--	--	--	239	G	0% gas recirculation
					"				210	G	7.9% gas recirculation
					"				202	G	15.4% gas recirculation
					"	--	--	--	222	G	207°F oil temperature
					"				219	G	238°F " "
					"				202	G	242°F " "
					"				202	G	243°F " "
					"				184	G	277°F " "
15[a]	General	--	--	--	--	--	--	--	90% sulfur to SO_x 1-5% SO_2 to SO_3 0.02-0.04 gr/scf 100-900 ppm NO_x		
	--	--	--	--	Horizontal	--	--	--	500-700 ppm NO_x		--
					Tangential	--	--	--	200-400 ppm NO_x		--
16[a]	General	--	--	--	--	--	--	--	600 ppm SO_2/1% sulfur in fuel 1-2% SO_2 to SO_3 100-900 ppm NO_x		Ash, < 1 to 40 μ
17[a]	No, general	175	--	--	--	--	--	--	120 lb/hr dust 13.1 ppm (average) SO_3 310-915 ppm NO_x Two-stage combustion reduced from 685 to 350 ppm NO_x CO, 100 ppm or less in inefficient boiler		Dust, 0.4 μ
18	Typical	--	--	--	--	--	--	--	310-915 ppm NO_x Dust, 0.14 lb/1,000 lb oil 1-5% sulfur to SO_3 SO_2, 2,200 ppm @ 14% CO_2		4% sulfur in oil

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
1[a]	--[b]	175	--	--	--	--	--	--	75 lb/hr solids 13.1 ppm SO_3 330 - 915 ppm NO_x > 100 ppm CO (For poor combustion)	Dust 0.4μ (about) indicates 90% < 0.5μ
14	--		--	--	Horizontal " " Tangential " "	--	--	--	ppm NO_x — Plant: 685 — El Segundo 567 — A 505 — B 482 — C 362 — E 309 — F 209 — G	Normal full load
					Horizontal " Tangential	--	--	--	385 — El Segundo 276 — B 160 — G	Two-stage combustion
					Horizontal " " Tangential " " "	--	--	3.5% O_2 3.1% O_2 2.3% O_2 4.2% O_2 3.0% O_2 2.9% O_2 2.2% O_2	681 & 699 — C 637 & 681 — C 456 & 508 — C 258 — G 202 — G 219 — G 184 — G	Excess air variation

GPO 801—939—5

								3.1	454	
								3.1	471	
								3.1	480	
								3.1	488	
								4.5	557	
								4.5	578	
								4.5	596	
								5.2	638	
								5.2	626	
								5.2	604	
								5.3	591	
								2.7	338	55% load
								2.7	345	12 burners
								2.8	386	
								2.8	369	
								4.3	531	
								4.3	523	
								4.3	497	
								2.4	300	55% load
								2.4	266	16 burners
								2.4	240	
								3.3	381	
								3.3	369	
								3.3	347	
								4.1	420	
								4.1	411	
								4.1	394	
								4.1	377	
								5.2	540	
								5.2	531	
								5.3	548	
								5.3	557	
		70	--	--	--	--	--	3.0	381	--
									300	

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
19	Yes[d]	--	--	--	--	--	--	% O_2	ppm NO_x:	
								2.4	642	100% load,
								2.4	634	16 burners
								3.3	634	
								3.3	659	
								3.3	668	
								3.5	694	
								3.5	711	
								3.5	745	
								2.5	437	85% load,
								2.5	531	16 burners
								3.3	557	
								3.3	600	
								4.0	582	
								4.0	604	
								4.2	583	
								4.2	600	
								5.7	660	
								5.7	677	
								2.4	420	70% load,
								2.6	420	16 burners
								2.6	394	
								3.1	446	

												488 462 428 420	30
												471 462 450 437	45
												471 432 411 402	60
												407 394 385 364	75
		--	--	--	--	--	--						
											2.5 2.8 3.2 3.4 3.5 4.0 4.5 4.6 4.7 5.4	454 471 497 471 497 535 548 540 557 561	Oil pressure at burner tip, 390 psig
											2.0 2.2 2.8	325 342 377	Oil pressure at burner tip, 480 psig

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler			Flue gas			Emissions	Notes and miscellaneous
			Steam rate, 1,000 lb/hr	Firing rate, 1,000 lb/hr	Type of firing	Volume, 1,000 scfm	Temp, °F	Orsat (%) CO, CO_2, O_2	Particulates and gases	
19 (cont'd)		95	--	--	--	--	--	% O_2: 3.0	ppm NO_x: 471 450 394 342 325	--
		120	--	--	--	--	--	3.0	492 471 462 428 407 385 377	--
		150	--	--	--	--	--	3.0	540 531 514 432	--
		175	--	--	--	--	--	3.0	578 557 514 445	--
		156	--	--	--	--	--	--	514 492 450 445	Air register, % open: 15

		150	--	74	--	--	--	2.0 2.3 2.7 2.9 3.4 3.5 3.8 3.8 4.5 4.5	552 514 561 561 600 608 638 621 651 664	Dirty boiler
								2.5 2.8 3.1 3.3 3.3 3.8 4.4 4.5 4.7 5.3	454 471 492 475 505 535 548 539 557 557	Clean boiler
	Yes (general average)	--	--	--	--	--	--	--	0.78 lb NO_x/10^6 Btu or 14.2 lb NO_x/1,000 lb oil fired, calculated using 18,300 Btu/lb oil	Based on 130 tests and 554 individual samples
20	General	100 or greater	--	about 50	--	250 to 300	--	--	Dust, 1-5 lb/1,000 lb oil at low pressure atomization 2/3 reduced with good atomization SO_2, 30 lb/1,000 lb oil SO_3, 1-2.5 lb/1,000 lb oil NO_x, 400-600 ppm	1.5% sulfur in oil Particles are both solid and liquid. Liquid part is H_2SO_4 Typical size distribution for carbon particles, 95% is 10-1,000 Specific gravity, 2.5 of particulates. 50-75% carbon, rest ash

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler			Flue gas			Emissions	Notes and miscellaneous
			Steam rate, 1,000 lb/hr	Firing rate, 1,000 lb/hr	Type of firing	Volume, 1,000 scfm	Temp, °F	Orsat (%) CO, CO_2, O_2	Particulates and gases	
19 (cont'd)								%O_2:	ppm NO_x:	
								3.2	372	
								3.4	381	
								3.5	377	
								3.6	450	
								4.1	480	
								5.0	514	
								--	475	14 burners, oil pressure at burner tip, 345 psig
									462	
									411	12 burners, oil pressure at burner tip, 405 psig
									420	
									407	10 burners, oil pressure at burner tip, 505 psig
									402	
		150	--	--	--	--	--			16 burners
								3		Air register, % open:
									411	65
									471	70
									497	80
									505	90
									535	100
		126	--	--	--	--	--	3	364	65
									372	70
									411	80
									428	90
									437	100

Actual:							Dust, gr/scf:	NO_x, ppm:	Oil temp, °F:	Combustible, % in dust:
186							0.068	219	238	87.98
185							0.101	207	238	95.24
183							0.035	201	242	79.49
185							0.033	202	242	78.63
185							0.105	222	207	88.03
185							0.032	184	277	73.15
181							0.033	212	276	72.75
173							0.029	248	241	79.59
163							0.026	239	241	88.37
159							0.023	240	242	73.75
185							0.028	245	241	74.36
177							0.029	281	241	77.48
173							0.028	258	243	75.02
178							0.142	184	242	90.62
176							0.060	202	243	86.07
169							0.030	210	242	83.87
183							0.028	283	242	66.23
186							0.027	193	242	65.72
184							0.033	188	242	
180							0.049	196	242	71.49
184							0.028		240	
184							0.064		240 soot blowing	
	--	--		--	--	--			Fuel analysis: 9.1 API, 18,050 Btu/lb, 86.9% C, 10.55% H_2, 2.05% sulfur, 0.50% N_2 + O_2 (by difference), 0.01% ash	

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler			Flue gas			Emissions		Notes and miscellaneous
			Steam rate, 1,000 lb/hr	Firing rate, 1,000 lb/hr	Type of firing	Volume, 1,000 scfm	Temp, °F	Orsat (%) CO, CO_2, O_2	Particulates and gases		
20 (cont'd)											Ash is light brown, 1-, 30 to 60% soluble, initial pH 3, size 0.5 to 1- Visible plume due to particles 1- or less in size Good power plant operation
21	General	--	--	--	--	--	--	--		lb/1,000 lb oil fired:	
									NO_x as NO_2	17.6	(Converted from lb/10^3 bbl, using 10 API oil.)
									SO_2	31.4	Based on many samples, all stationary sources
									CO	0.0051	
									Aerosol	2.5	
									Hydrocarbons	0.097	
									Aldehydes & Ketones	0.071	
									Other organics	0.326	
23	Yes	Normal, 110	--	--	Tangential	--	--	--			Fuel analysis: 10.6 API, 18,210 Btu/lb, 86.3% C, 10.28% H_2, 2.3% sulfur, 0.06% ash, and 1.03% $N_2 + O_2$ (by difference) Steam, 1,050°/1,000°F

25[a]	Typical	--	1,170	86	Mechanical atomizing	--	--	--	450 ppm NO_x as NO_2 55 ppm SO_3 0.022 gr/scf dust loading	Full load	Fuel analysis: 6.2 API, 610 sec Furol at 122°F, 1.3% sulfur, 0.06% ash, 18,040 Btu/lb
									325 ppm, NO_x as NO_2 35 ppm, SO_3	1/2 load	Light plume from stack
									740 ppm SO_2 (calculated)	all loads	Boiler pressure, 850 psi, temp, 1,000°F
26	Yes	--	450	30	--	--	--	--	38 ppm SO_3, air heater inlet 28 ppm SO_3, air heater outlet	full load	2.4-3.3% sulfur in oil
									37 ppm SO_3, air heater inlet 29 ppm SO_3, air heater outlet	1/2 load	
27	--	--	--	--	--	--	--	--	100% sulfur in oil out stack		--
29[a]	Yes	--	--	--	--	--	--	15.4% CO_2 0.7% O_2 0.033% CO	SO_3, ppm, without additives: / SO_3, ppm, with additives: 40 / 18 15 / 3-5 15 / 8-10 44 / 10 38 / 18	4.2% sulfur in the oil	
	General	--	--	--	--	--	--	--	2% of the sulfur to SO_3		--

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
23 (cont'd)		Actual:							Dust, gr/scf: NO_x, ppm:	Oil temp, °F: Combustible, % in dust:
		174								
		174							220	232
		171							232	232
		174							252	232
		172							0.033 227	228 74.15
		172							0.047 226	234 73.85
		172							0.059 203	230 74.61
		174							0.089 198	228 76.65
		173							192	232
		174							226	230
		172							0.091 172	228 75.17
		172							196	234
		170							212	234
		169							0.055 [illegible]8	208 75.49
		162							0.049 [illegible]9	238 76.27
		182							0.031	277 64.72
		182							0.037 [illegible]	232 61.10
		183							0.076 269	232 73.08
		182							0.043 277	230
		182							0.048 206	232 68.22
		182							0.046 242	239 65.45
									0.026 246	231 69.24
24	Yes	--	1,140	--	--	--	--	--	685 ppm NO_x normal 575 ppm NO_x removed approach-cone vanes 305 ppm NO_x two-stage combustion and no approach-cone vanes	Steam, 1,860 psi 1,000°F

									17 3.25 16 3.5 27 3.5 15 4.1 21 4.1 30 4.1 31 4.1 38 4.4 40 4.4 15 4.5 23 4.5 22 5.0 30 5.0 36 5.0 40 5.0 29 5.1 33 5.2	
35	Yes	--		--	--	--	--	% CO_2:	SO_3, ppm:	Steam 925°F. and 950 psi. Residual fuel contains 3.6-3.7% sulfur Maximum rating 375,000 lb/hr steam
			375					10.1	38	
			328					10.6	22.6	Measured in primary super heater
			350					10.6	19.3	
			341					10.7	22.4	
			352					10.9	50.6	
			380					11.9	56.5	
			353					11.5	45	
			380					10.1	75	
			350					12.2	27.5	Secondary super heater
			360					12.3	50.8	

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler			Flue gas			Emissions		Notes and miscellaneous
			Steam rate, 1,000 lb/hr	Firing rate, 1,000 lb/hr	Type of firing	Volume, 1,000 scfm	Temp, °F	Orsat (%) CO, CO_2, O_2	Particulates and gases		
31[a]	Yes	--	--	--	--	--	--	--	SO_3, ppm:	% sulfur in oil:	Added sulfur to some of the oils. Data was taken from a curve
									10	0.2	
									12	0.2	
									14	0.5	
									17	0.5	
									8	1.2	
									18	1.2	
									10	1.7	
									17	1.7	
									21	1.75	
									23	1.75	
									18	1.8	
									20	1.8	
									15	1.9	
									22	2.2	
									31	2.3	
									18	2.7	
									20	2.7	
									22	2.7	
									30	2.7	
									18	3.2	
									25	3.2	
									32	3.2	

40	Typical	--	--	--	--	--	--	--	lb/1,000 lb oil: 13 NO_x 0.25 Solids 30 SO_x 1.2 Aldehydes 15 Acids (as HOAC) 5 Organics	--
41	Yes	--	1,140	82.5	--	415	--	9.9 CO_2	0.0515 gr/scf dust	Fuel analysis: 4° API, 1.6% sulfur, 8.5% moisture in stack
			850	61	--	250	--	8.6 CO_2	0.0325 gr/scf dust	Fuel analysis: 8.7° API, 1.4% sulfur, 7.8% moisture in stack
	General	--	--	--	--	--	--	--	lb/1,000 lb oil: SO_2 28.82 & 39 SO_3 0.037 & 0.07 NO_x 5.0 & 28.05 Organic acid (as acetic) 0.235 & 0.41 Aldehydes (as formaldehyde) nil & 0.65 Hydrocarbons (as hexane) 0.28 & 0.095 Acetylene nil & 0.03	Results of 2 tests
42	No, typical estimates	--	--	--	--	--	688	0.0% CO, 14.6% CO_2, 3.0% O_2, 82.4% N_2	575 ppm NO_x 810 ppm SO_2 18.3 ppm SO_3 0.072 gr/scf solids (total) 0.049 gr/scf soluble solids	Author states that an electrostatic precipitator will reduce the SO_3 concentration by about 50%
43[a]	Yes	--	1,140	--	--	340	280	--	0.033 gr/scf dust enter collector 0.0033 gr/scf dust leave collector	Bunker C oil Electrostatic precipitator Dust 95% less than 0.5μ

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
38	General estimates	--	--	--	--	--	--	--	lb/1,000 lb oil: NO_x as NO_2 7 SO_2 20 SO_3 1 H_2S < 1 HCN < 1 NH_3 1 HCl < 1 CH_2O 1 Organics 5 Acids (as CH_3COOH) 15 Solids 1	Literature research for all oils. Data are general averages reported to be applicable to all sources in a major community.
39[a]	--	--	--	--	--	--	--	--	ppm: 0 Methane 0 Acetylene 0 Ethylene 13 Other hydrocarbons (as propane) 0 CO 0 NO_2 0 NO	Infrared measurement techniques

46[a]	Yes	--	--	--	--	--	--	--	gr/scf dust: / Plant:	Fuel, type:
									0.11 A	PS400 During lancing
									0.16 A	PS400
									0.18 A	PS400
									0.20 A	PS400
									0.03 B	PS400
									0.09 B	PS400 During lancing
									0.05 C	4° API
									0.05 C	4° API
									0.04 C	4° API
										Plant B had collection device called a Multi-clone that removed nearly all the ceno-spheres. A plume was still visible
										53% greater 4μ. 30-40% combustible (general), but has found 94% combustible. 0.09 to 0.29 ash in fuel/total loading 17 to 25% SO_3 in ash (include H_2SO_4 droplets)
50	Yes	175	1,150	85	Horizontal mechanical atomizing	283	300	12.9 CO_2 3.4 O_2 83.7 N_2	gr/scf: / ppm:	Fuel analysis: 87.13% C, 9.64% H_2, 1.35% S, 1.10% N_2, 0.01% ash
									599 NO_x	Steam[c]: 1,000/1,000°F and 2,000 psig
									703 SO_2	
									12.5 SO_3	
									0.0316 Total dust loading	
									0.0075 Soluble solids	

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
44	General	--	--	--	--	--	--	--	lb/1,000 lb oil: NO_x as NO_2 13 SO_2 16 times % sulfur in oil SO_3 2 times % sulfur in oil Solids 0.25 Ammonia 0.006 Organic Acids (as acetic) 15 Aldehydes (as formaldehyde) 1.23 Total hydrocarbons 5	Solids 1μ in diam or less. Literature research for all oils
45[a]	Yes	--	--	--	--	182	325	--	Particles collected in cyclone, 0.0580 gr/scf Particles collected in precipitator, 0.1083 gr/scf	Particle size, above 3-4μ = 53% under 3μ = 47% Particle analysis: Free carbon 63.2% Vol combustible (ether soluble) 2.3% Acid soluble volatile noncombustible 18.9% Loss on ignition 84.4% Ash 15.6% 100.0%

		20	215	12.5	Horizontal mechanical atomizing	47.3	300	12.2 CO_2 5.4 O_2 82.4 N_2	0.0446 0.00057	Total dust loading Soluble solids	Fuel analysis: 87.13% C, 9.95% H_2, 1.58% S, 1.08% N_2, 0.06% Ash Steam: 900°F and 1,150 psig
		175	1,150	82.5	Horizontal mechanical atomizing	281	300	12.9 CO_2 4.0 O_2 83.1 N_2	 0.0354 0.0026	374 NO_x as NO_2 796 SO_2 8.7 SO_3 Total dust loading Soluble solids	Fuel analysis: 87.33% C, 9.37% H_2, 1.53% S, 1.18% N_2, 0.12% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
		Common steam heater to turbine	410	29.6	Horizontal mechanical atomizing	116	330	11.4 CO_2 6.5 O_2 82.1 N_2	 0.0855 0.0074	551 NO_x as NO_2 709 SO_2 9.5 SO_3 Total dust loading Soluble solids	Fuel analysis: 87.33% C, 9.37% H_2, 1.53% S, 1.18% N_2, 0.12% Ash Steam: 900°F and 850 psig
		215	1,400	105	Horizontal mechanical atomizing	309	280	14.6 CO_2 2.4 O_2 83.0 N_2	 0.0294 0.0141	508 NO_x as NO_2 763 SO_2 14.0 SO_3 Total dust loading Soluble solids	Fuel analysis: 86.9% C, 9.6% H_2, 1.4% S, 0.9% N_2, 0.08% Ash Steam[c]: 1,050/1,000°F and 2,500 psig

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 acfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases		Notes and miscellaneous
									gr/scf:	ppm:	
50 (cont'd)		173	1,150	86	Horizontal mechanical atomizing	333	390	12.9 CO_2 4.2 O_2 82.9 N_2		317 NO_x 132 SO 20.4 SO_2	Fuel analysis: 87.34% C, 9.33% H_2, 1.50% S, 1.16% N_2, 0.07% ash Steam: 1,000/1,000°F and 1,000 psig
									0.0420	Total dust loading	
									0.0079	Soluble solids	
		30	275	18.5	Horizontal mechanical atomizing	69	310	11.6 CO_2 6.6 O_2 81.8 N_2			Fuel analysis: 88.66% C, 9.42% H_2, 0.94% S, 1.04% N_2, 0.01% Ash Steam: 900°F and 950 psig
									0.0160	Total dust loading	
									0.00235	Soluble solids	
		41	450	21.7	Horizontal mechanical atomizing	91.2	320	12.2 CO_2 5.5 O_2 82.3 N_2	0.0176	Total dust loading	Fuel analysis: 85.94% C, 10.78% H_2, 1.34% S, 0.79% N_2, 0.066% Ash Steam: 950°F and 1,500 psig
									0.0012	Soluble solids	
		220	1,410	152	Horizontal mechanical atomizing	334	280	13.5 CO_2 2.9 O_2 82.6 N_2		684 NO_x 812 SO 10.4 SO_2	Fuel analysis: 87.24% C, 9.52% H_2, 1.52% S, 1.06% N_2, 0.06% Ash Steam: 1,050/1,000°F and 2,500 psig
									0.0258	Total dust loading	
									0.008	Solid[1] solids	

| | | |

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 acfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
50 (cont'd)		215	1,400	107	Horizontal mechanical atomizing	314	280	14.3 CO_2 2.8 O_2 82.9 N_2	gr/scf: ppm: 451 NO_x as NO_2 765 SO_2 28.2 SO_3 0.0326 Total dust loading 0.0155 Soluble solids	Fuel analysis: 86.9% C, 9.6% H_2, 1.4% S, 0.9% N_2, 0.06% Ash Steam[2]: 1,050°/1,000°F and 2,500 psig
		215	1,390	105	Horizontal mechanical atomizing	309	280	14.9 CO_2 2.3 O_2 82.8 N_2	438 NO_x as NO_2 730 SO_2 17.7 SO_3 0.0330 Total dust loading 0.0064 Soluble solids	Fuel analysis: 86.9% C, 9.6% H_2, 1.4% S, 0.9% N_2, 0.06% Ash Steam[2]: 1,050°/1,000°F and 2,500 psig
		215	1,400	104	Horizontal mechanical atomizing	309	280	14.6 CO_2 2.5 O_2 82.9 N_2	385 NO_x as NO_2 750 SO_2 15.9 SO_3 0.0347 Total dust loading 0.0116 Soluble solids	Fuel analysis: 86.9% C, 9.6% H_2, 1.4% S, 0.9% N_2, 0.06% Ash Steam[2]: 1,050°/1,000°F and 2,500 psig

90	530	46	Horizontal mechanical atomizing	155	280	12.7 CO_2 4.7 O_2 82.6 N_2	328 NO_x as NO_2 651 SO_2 7.4 SO_3	Fuel analysis: 87.53% C, 9.77% H_2, 1.57% S, 1.17% N_2, 0.14% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
175	1,200	89	Horizontal mechanical atomizing	268	300	13.8 CO_2 3.5 O_2 82.7 N_2	561 NO_x as NO_2 701 SO_2 4.6 SO_3	Fuel analysis: 87.53% C, 9.77% H_2, 1.57% S, 1.17% H_2, 0.14% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
175	1,200	89	Horizontal mechanical atomizing	289	300	13.8 CO_2 3.4 O_2 82.8 N_2	301 NO_x as NO_2 685 SO_2 2.8 SO_3	Fuel analysis: 87.53% C, 9.77% H_2, 1.57% S, 1.17% N_2, 0.14% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
132	950	66	Tangential mechanical atomizing	216	270	10.8 CO_2 6.8 O_2 82.4 N_2	357 NO_x as NO_2	Fuel analysis: 87.15% C, 9.78% H_2, 1.35% S, 1.25% N_2, 0.07% Ash Steam[c]: 1,000/1,000°F and 1,950 psig
132	950	65	Tangential mechanical atomizing	206	270	11.1 CO_2 6.6 O_2 82.3 N_2	279 NO_x as NO_2	Fuel analysis: 87.15% C, 9.78% H2, 1.35% S, 1.25% N_2, 0.07% Ash Steam[c]: 1,000/1,000°F 1,950 psig
173	1,150	87	Horizontal mechanical atomizing	322	300	12.6 CO_2 4.0 O_2 83.4 N_2	431 NO_x as NO_2 216 SO_2 6.2 SO_3 0.0194 Total dust loading 0.0107 Soluble solids	Fuel analysis: 87.03% C, 11.84% H_2, 0.47% S, 0.48% N_2, 0.039% Ash Steam[c]: 1,000/1,000°F and 2,000 psig

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
50 (cont'd)		75	430	37	Horizontal mechanical atomizing	141	200	11.7 CO_2 5.9 O_2 82.4 N_2	gr/scf: ppm: 315 NO_x as NO_2	Fuel analysis: 86.9% C, 9.6% H_2, 1.4% S, 0.9% N_2, 0.08% Ash Steam[c]: 1,050/1,000°F and 2,000 psig
		173	1,150	87	Horizontal mechanical atomizing	330	300	12.3 CO_2 4.0 O_2 83.7 N_2	332 NO_x as NO_2 128 SO_2 7.5 SO_3 0.0159 Total dust loading	Fuel analysis: 87.42% C, 12.58% H_2, 0.38% S, 0.32% N_2, 0.04% Ash Steam[c]: 1,000/1,000°F amd 2,000 psig
		173	1,200	90	Horizontal mechanical atomizing	387	300	14.1 CO_2 3.1 O_2 82.8 N_2	524 NO_x as NO_2 725 SO_2 12.5 SO_3	Fuel analysis: 87.53% C, 9.77% H_2, 1.57% S, 1.17% H_2, 0.14% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
		173	1,200	90	Horizontal mechanical atomizing	287	300	14.2 CO_2 3.1 O_2 82.7 N_2	370 NO_x as NO_2 733 SO_2 11.2 SO_3	Fuel analysis: 87.53% C, 9.77% H_2, 1.57% S, 1.17% N_2, 0.14% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
		90	550	46	Horizontal mechanical atomizing	150.5	280	12.1 CO_2 4.4 O_2 83.5 N_2	441 NO_x as NO_2 639 SO_2 10.8 SO_3	Fuel analysis: 87.53% C, 9.77% H_2, 1.57% S, 1.17% N_2, 0.14% Ash Steam[c]: 1,000/1,000°F and 2,000 psig

										21	3.1	
										31	3.1	
										20	3.2	
										15	3.3	
										17	3.3	
										18	3.3	
										14	3.5	
										With additives,		
										SO_3, ppm:	% sulfur in oil:	
										3	3.2	
										2	3.2	
										3	3.4	
										6	3.4	
										5	3.7	
										8	3.8	
										3	3.8	
										2	3.8	
64	No. Reports other work	--	Actual steam rate:	--	--	--	--	% CO_2:	% O_2:	SO_2, ppm:	SO_3, ppm:	Normal steam rate, 1000 lb/hr: Plant:
			20.3					7.0	13.2	1,530 1,530	23.8 23.8	20 A
			30.7	--	--	--	--	8.4	--	1,430 1,430	17 20	30 B
			30.0	--	--	--	--	11.4	5.2	1,360	17	30 C
			29.5	--	--	--	--	10.7	--	1,120 1,120	18 17	30 D
			30.1	--	--	--	--	10.6	--	790 680	21.5 18	30 E
			30.1	--	--	--	--	10.6	--	710 595	12 10.5	30 F

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
50 (cont'd)		173	1,150	85	Horizontal mechanical atomizing	306	300	12.7 CO_2 3.8 O_2 83.5 N_2	gr/scf: ppm: 393 NO_x as NO_2 269 SO_2 7.1 SO_3	Fuel analysis: 86.78% C, 11.99% H_2, 0.68% S, 0.59% N_2, 0.028% Ash Steam[c]: 1,000/1,000°F and 2,000 psig
59	General	175	--	167	--	600	--	--	11 lb NO_x/1,000 lb oil 1,000 ppm SO_2 (approximate) 0.5 lb dust/1,000 lb oil 30 lbs SO_2/1,000 lb oil	Residual oil with 1.5% sulfur in oil
63	Yes	--	--	--	--	--	--	--	Without additives, SO_3, ppm: / % sulfur in oil: 2 / 1.5 13 / 1.5 17 / 1.5 22 / 2.2 23 / 2.2 33 / 2.2 35 / 2.2 18 / 2.4 20 / 2.4 31 / 2.4 18 / 2.5	Data were read from a graph

GPO 801-939-7

			39.3	--	--	--	--	10.8	6.0	1,340	16.5	40	H	
			39.7	--	--	--	--	13.5	--	1,150 1,150	11.5 14	40	I	
			50.5	--	--	--	--	13.3	--	1,350	24.5	Maximum	J	
												Fuel analysis: 22.1° API 85.6% C, 11.92% H_2, 2.00% S, 0.22% N_2, 0.03% Ash Low viscosity fuel oil from asphaltic crude		
			21.0	--	--	--	--	7.6	10.6	1,260 1,260	22 25	20	A	
			30.0	--	--	--	--	8.6	8.8	1,400 1,120	24 10	30	B	
			30.7	--	--	--	--	10.8	6.4	1,110 1,330	12 11	30	C	
			30.5	--	--	--	--	11.5	5.6	1,150 1,150	10.5 7.3	30	D	
			30.9	--	--	--	--	12.8	4.4	1,030 1,038	5.5 7.5	30	G	
			38.9	--	--	--	--	11.0	5.8	1,310 1,090	13 14	40	H	
			39.9	--	--	--	--	14.0	2.2	1,030 1,200	8.5 8.5	40	I	
			49.3	--	--	--	--	13.5	2.1	1,070	9	Maximum	J	
												Fuel analysis: 21° API 86.3% C, 11.92% H_2, 2.10% S, 0.23% N_2, 0.03% Ash Medium viscosity fuel from mixed base crude		

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate, 1,000 lb/hr	Boiler: Firing rate, 1,000 lb/hr	Boiler: Type of firing	Flue gas: Volume, 1,000 scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
64 (cont'd)	No; reports other work		Actual steam rate:						SO_2, ppm: / SO_3, ppm:	Normal steam rate, 1000 lb/hr: / Plant:
			31.8	--	--	--	--	12.8 3.4	1,600 / 16 1,310 / 19	30 / G
			37.6	--	--	--	--	10.8 --	1,450 / 23.5	40 / H
			40.6	--	--	--	--	14.0 4.6	1,110 / 26.5 -- / 21.5	40 / I
			50.6	--	--	--	--	13.7 --	1,400 / 20	Maximum / J
										Fuel analysis: 2.6% S, 0.08% Ash, 85% C, 11.17% H_2, 0.39% N_2, 14.3° API Marine fuel oil from asphaltic crude
			20.2	--	--	--	--	8.0 9.8	750 / 22.5 750 / 24	20 / A
			30.5	--	--	--	--	8.8 8.0	950 / 20.5 1,100 / 19	30 / B
			30.3	--	--	--	--	11.0 --	1,200 / 13 1,200 / 18.5	30 / C
			30.7	--	--	--	--	11.1 5.0	1,080 / 10	30 / D
			31.3	--	--	--	--	10.6 6.5	800 / 8 900 / 9	30 / E
			31.0	--	--	--	--	11.2 --	320 / 10.7 440 / 10.7	30 / F
			30.7	--	--	--	--	12.8 4.3	940 / 12 940 / 12	30 / G

										Fuel analysis: 85.20% C, 11.6% H_2, 3.55% S, 0.15% N_2, 0.02% Ash Heavy fuel oil from mixed base crude of higher sulfur content
65	No, general	--	--	--	--	--	--	--	13.5 lb NO_x/1,000 lb oil or 17 lb NO_x/1,000 lb oil or 10 lb NO_x/1,000 lb oil	Author reports that these values have been established for fuel oil
66	General	--	--	--	--	--	--	--	30 lb SO_2/1,000 lb oil 13.5 lb NO_x as NO_2/1,000 lb oil 2.5 lb solids/1,000 lb oil	Fuel analysis: 1.5% sulfur
67[a]	Yes	--	--	--	--	--	--	--	SO_2, ppm: / SO_3, ppm: / Theoretical sulfur:	Test
									1,140 / 33 / 1,260	1
									1,280 / 23 / 1,260	1
									1,230 / 32 / 1,260	1
									1,930 / 20 / 1,900	2
									1,890 / 19 / 1,900	2
									870 / 20 / 860	3
									890 / 14 / 860	3
									890 / 17 / 860	3

[a] 12% CO_2 correction not known.

[b] --No data.

[c] Super heat temperature/reheat temperature.

[d] Data read from a graph and corrected from 3% O_2 to 12% CO_2.

APPENDIX A. DETAILED DATA ON LARGE SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler			Flue gas			Emissions		Notes and miscellaneous	
			Steam rate, 1,000 lb/hr	Firing rate, 1,000 lb/hr	Type of firing	Volume, 1,000 scfm	Temp, °F	Orsat (%) CO, CO_2, O_2	Particulates and gases			
64 (cont'd)			Actual steam rate:					% CO_2: % O_2:	SO_2, ppm:	SO_3, ppm:	Normal steam rate, 1000 lb/hr:	Plant:
			19.5	--	--	--	--	7.9 --	1,220 1,370	14 23	20	A
			30.5	--	--	--	--	8.7 --	1,240 1,240	16.5 18	30	B
			30.4	--	--	--	--	10.6 6.3	1,580 1,470	16 12.5	30	C
			30.8	--	--	--	--	10.8 4.8	1,330	14.5	30	D
			31.1	--	--	--	--	11.3 5.1	1,170 1,060	10.5 15	30	E
			31.0	--	--	--	--	10.5 --	230 230	5.5 7	30	F
			31.0	--	--	--	--	13.0 2.7	1,110 1,290	7.5 9	30	G
			41.3	--	--	--	--	11.2 5.5	1,500 1,500	10.5 12	40	H
			41.9	--	--	--	--	13.0 3.3	1,570 1,570	7.5 8.5	40	I
			48.3	--	--	--	--	13.6 --	1,590 1,590	12.5 9	Maximum	J

							620	10.8	0.011	0.011	69	3
							680	9.5	0.025	0.025	66	1
							700	8.3	0.725	0.217	63	0
											Domestic fuel	
68 b c d e	Yes	--	2,070 lb/hr	65.2	Pressure atomizing	368	250	0.01 CO 7.0 CO_2 7.9 O_2	lb/1,000 lb oil:	gases in ppm, particles in gr/scf:	Fuel analysis: PS 200, 31.07° API, 1.05% S, 0.02% Ash Excess air, 65% Moisture in stack gas, 9.8% vol Oil temp, 70°F Steam, 70 psig Cyclotherm steam generator boiler, fire tube, 60 hp	
									21.5	355 SO_2		
									0.123	1.6 SO_3		
									0.261	9 Aldehydes		
									1.98	47 NO_x as NO_2		
									2.15	0.065 Particles		
			3,450 lb/hr	44.7	Pressure atomizing	480	290	0.000 CO 3.9 CO_2 15.7 O_2	11.4	98.2 SO_2	Fuel analysis: PS 200, 28.71° API, 0.71% S, 0% Ash Excess air, 290% Moisture in stack gas, 4.7% vol Oil temp, 70°F Brayan No. 315 -- 100 hp water tube (hot water)	
									0.206	1.4 SO_3		
									0.292	5 Aldehydes		
									2.92	35.8 NO_x as NO_2		
									2.24	0.067 Particles		
			4,140 lb/hr	288	Steam atomizing	1,700	710	0.003 CO 7.0 CO_2 7.8 O_2	26.0	414 SO_2	Fuel analysis: PS 300, 16.51° API, 1.0% S, 0% Ash Excess air, 68% Moisture in stack gas, 12.7% vol Oil temp, 160°F Steam, 100 psig Locomotive type boiler -- 120 hp, single pass fire tube	
									0.348	4.7 SO_3		
									0.173	7 Aldehydes		
									16.7	368 NO_x as NO_2		
									2.29	0.070 Particles		

APPENDIX B. DETAILED DATA ON SMALL SOURCE EMISSIONS

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate	Boiler: Firing rate, lb/hr	Boiler: Type of firing	Flue gas: Volume, acfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
21	Yes	--[1]	--	--	--	--	--	--	lb/1,000 lb oil fired: NO_x as NO_2 7.2 SO_2 21.2 CO nil Aerosol 1.7 Hydrocarbons 0.060 Aldehydes and ketones 0.063 Other organics 0.177	Domestic and commercial sources
46	Yes	--	150 hp *or* 5,160 lb/hr steam	--	Steam atomizing	--	--	--	0.06 gr/scf dust	Horizontal return tube boiler, PS400 oil
51	Yes (519 total, general	--	500 hp *or* less	--	--	--	--	--	0.49 lb, $NO_x/10^6$ Btu *or* 9 lb NO_x/1,000 lb oil[2]	--
52	Yes	--	500,000 Btu/hr	--	--	--	--	%CO_2: %CO:	% H_2:	Thermal efficiency, %: Shell smoke no:
							570	12.4 1.16	0.58	65.5 9
							620	11.5 0.156	0.104	70 6

			6,000 lb/hr	88.5	Pressure atomizing	1,200	370	0.008 CO 2.6 CO_2 10.3 O_2	0.005 0 0.005 1.85 0.85	0.9 0 4 14.0 0.0065	ppm ppm Aldehydes NO_x as NO_2 Particles	Fuel analysis: 31.0° API, 0.55% S, 0% Ash Excess air, 270% Moisture in stack gas, 3.0% vol Oil temp, 70°F Steam, 120 psig Diesel fuel, B & W boiler, model FM-27 -- 200 hp, water tube
			8,450 lb/hr	830	MCL 7-23	4,970	540	0.00 CO 7.0 CO_2 6.0 O_2	31.1 0.0044 0.004 14.72 1.80	567 0.27 0 567 0.0010	ppm ppm Aldehydes NO_x as NO_2 Particles	Fuel analysis: PS 400, 11.10° API, 0.94% S, 0.12% Ash Excess air, 42% Moisture in stack gas, 10.7% vol Oil temp, 205°F Steam, 120 psig Erie City boiler, model 60-16 -- 245 hp water tube, 3 drum
			10,350 lb/hr	185	Centrifugal	1,330	390	0.0024 CO 5.5 CO_2 10.9 O_2	0.01 0.0005 0.040 1.48 0.89	105 0.1 7 55.0 0.0008	ppm ppm Aldehydes NO_x as NO_2 Particles	Fuel analysis: PS 200, 33.01° API, 0.21% S, 0.07% Ash Excess air, 115% Moisture in stack gas, 6.9% vol Oil temp, 70°F Steam, 600 psig B & W boiler type FM-1 -- 300 hp, water tube

APPENDIX B. DETAILED DATA ON SMALL SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate	Boiler: Firing rate, lb/hr	Boiler: Type of firing	Flue gas: Volume, acfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
68 (cont'd)			4,210 lb/hr	190.5	Pressure atomizing	1,700	330	0.000 CO 5.0 CO_2 13.3 O_2	(lb/1,000 lb oil) grams or ppm, particles in gr/scf 86.2 284 Wtg 0.336 1.2 Wtg 0.021 0 Aldehydes 0.62 120 NO_2 as Wtg 0.04 0.156 Particles	Fuel analysis: PS 300, 11.39° API, 1.78% S, 0.18% Ash Excess air, 180% Moisture in stack gas, 4.6% vol Oil temp, 70°F Steam, 90 psig Pioneer boiler -- 125 hp, Scotch Marine
			5,170 lb/hr	105	Centrifugal atomizing	1,600	340	0.001 CO 2.7 CO_2 16.2 O_2	4.57 24 Wtg 0.940 1.7 Wtg 0.061 0 Aldehydes 0.58 80 NO_2 as Wtg 1.14 0.606 Particles	Fuel analysis: 40.10° API 0.09% S, 0% Ash Excess air, 150% Moisture in stack gas, 4.6% vol Oil temp, 70°F Steam, 10 psig Diesel fuel, Cabrial boiler -- 150 hp, Scotch Marine
			6,900 lb/hr	150	Centrifugal atomizing	1,890	360	0.02 CO 4.3 CO_2 13.9 O_2	65.9 11.8 Wtg 0.0004 5.4 Wtg 0.03 60 Aldehydes 0.47 51 NO_2 as Wtg 0.07 0.030 Particles	Fuel analysis: 33.82° API 0.97% S, 0% Ash Excess air, 210% Moisture in stack gas, 5.6% vol Oil temp, 70°F Steam, 90 psig Diesel fuel, Johnson boiler No. 18 -- 200 hp, Scotch Marine

			15,750 lb/hr	660	Pressure atomizing	4,560	220	0.0 CO 5.9 CO_2 10.7 O_2	26.7 0.197 0.303 10.5 1.20	362 2.2 7 199 0.0368	SO_2 SO_3 Aldehydes NO_x as NO_2 Particles	Fuel analysis: PS 300, 12.11° API, 0.78% S, 0.12% Ash Excess air, 107% Moisture in stack gas, 6.6% vol Oil temp, 190° F Steam, 275 psig Springfield boiler -- 460 hp, water tube
			17,250 lb/hr	1,975	Steam atomizing	12,400	560	0.000 CO 6.7 CO_2 9.5 O_2	40.0 0.304 0.506 12.4 1.42	594 3.6 17 256 0.0420	SO_2 SO_3 Aldehydes NO_x as NO_2 Particles	Fuel analysis: PS 300, 15.09° API, 1.39% S, 0.04% Ash Excess air, 92% Moisture in stack gas, 9.1% vol Oil temp, 160°F Steam, 145 psig Sterling boiler, model 477-31 (modified) -- 500 hp, water tube 4 drum
			20,000 lb/hr	467	Steam atomizing	3,030	580	0.0 CO 6.4 CO_2 9.6 O_2	45.0 0.195 0.257 9.22 1.86	690 2.3 8.5 295.9 0.037	SO_2 SO_3 Aldehydes NO_x as NO_2 Particles	Fuel analysis: PS 300, 13.33° API, 1.30% S, 0.03% Ash Excess air, 95% Moisture in stack gas, 9.8% vol Oil temp, 160°F Steam, 15 psig Collins boiler -- 580 hp, water tube

APPENDIX B. DETAILED DATA ON SMALL SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler			Flue gas			Emissions			Notes and miscellaneous
			Steam rate	Firing rate, lb/hr	Type of firing	Volume, scfm	Temp, °F	Orsat (%) CO, CO_2, O_2	Particulates and gases			
68 (cont'd)			10,350 lb/hr	280	Steam atomizing	2,930	320	0.0 CO 4.0 CO_2 13.9 O_2	lb/1,000	gases in ppm, particles in gr/scf:		Fuel analysis: PS 200, 34.87° API, 0.29% S, 0.01% Ash Excess air, 220% Moisture in stack gas 6.3% vol Oil temp, 60°F Steam, 100 psig Kewanee boiler, model 590 -- 300 hp, 2 pass fire tube
									8.00	7.1	SO_2	
									0	0.0	SO_3	
									0.285	6	Aldehydes	
									1.18	14.7	NO_x as NO_2	
									4.47	0.134	Particles	
			12,750 lb/hr	612	Centrifugal atomizing	3,970	500	0.000 CO 6.3 CO_2 9.8 O_2	11.75	17	SO_2	Fuel analysis: PS 200, 32.9° API, 0.42% S, 0% Ash Excess air, 94% Moisture in stack gas, 8.2% vol Oil temp, 70°F Steam, 150 psig Dixon wet back boiler -- 350 hp, Scotch Marine
									0	0	SO_3	
									0.098	3	Aldehydes	
									3.60	72	NO_x as NO_2	
									0.425	0.0132	Particles	
			14,700 lb/hr	1,350	Steam atomizing	10,000	630	0.001 CO 6.3 CO_2 10.3 O_2	55.6	700	SO_2	Fuel analysis: PS 400, 8.0° API, 3.06% S, 0% Ash Excess air, 110% Moisture in stack gas, 10.6% vol Oil temp, 210°F Steam, 160 psig Collins boiler -- 425 hp, water tube
									0.89	6.7	SO_3	
									0.148	4	Aldehydes	
									14.7	274.9	NO_x as NO_2	
									9.94	0.265	Particles	

										0 CO 13.4 CO_2 2.7 O_2	0.0945	12%	5
										1.0 CO 14.2 CO_2 1.3 O_2	0.2175	3%	7
											General value for particulates, 0.06 gr/scf	Normal steam rate, 8,000 lb/hr Double furnace Fuel analysis: PS 400, 15.9° API, 3.5% S, 0.05% Ash 18,700 Btu	

[a] Calculated using a 18,300 Btu/lb oil.

[b] 12% CO_2 correction is not known.

[c] Steam rate was calculated from the horsepower.

[d] Orsat analysis is on a wet basis.

[e] Aldehydes are calculated as formaldehydes.

[f] Dashes (--) indicate "no data".

Note: Also see references 38 and 44 in Large Sources (Appendix A)

APPENDIX B. DETAILED DATA ON SMALL SOURCE EMISSIONS (continued)

Reference	Original work	Nominal turbine load, mw	Boiler: Steam rate	Boiler: Firing rate, lb/hr	Boiler: Type of firing	Flue gas: Volume, scfm	Flue gas: Temp, °F	Flue gas: Orsat (%) CO, CO_2, O_2	Emissions: Particulates and gases	Notes and miscellaneous
68 (cont'd)			30,000 lb/hr	1,372	Steam atomizing	7,400	530	0.000 CO 8.2 CO_2 8.5 O_2	lb/1,000 lb oil: gases in ppm, particles in gr/scf: 19.8 344 SO_2 0.875 1.2 SO_3 1.31 48 Aldehydes 10.65 256 NO_x as NO_2 3.21 0.091 Particles	Fuel analysis: PS 400, 9.30°API, 1.94% S, 0.03% Ash Excess air, 73% Moisture in stack gas, 7.9% vol Oil temp, 220°F Steam, 275 psig B & W boiler, model FM -9 -- 870 hp, water tube
			--	37.1	Pressure atomizing	274	--	0.002 CO 5.4 CO_2 11.1 O_2	11.05 138 SO_2 0.081 2.8 SO_3 0.405 11 Aldehydes 1.75 33.7 NO_x as NO_2 2.18 0.069 Particles	Fuel analysis: PS 200, 33.6° API, 0.80% S. 0% Ash Excess air, 120% Moisture in stack gas, 7.8% vol Oil temp, 70°F Childers oil heater, model D-100, oil circulating heat exchanger
69	Yes	--	4,800 lb/hr	--	Pressure atomizing	--	--	0 CO 9.7 CO_2 8.0 O_2	gr/scf particles: 0.0615	Excess air: 59%; Shell smoke no: 3
								0 CO 12.4 CO_2 4.5 O_2	0.0775	Excess air: 26%; Shell smoke no: 4

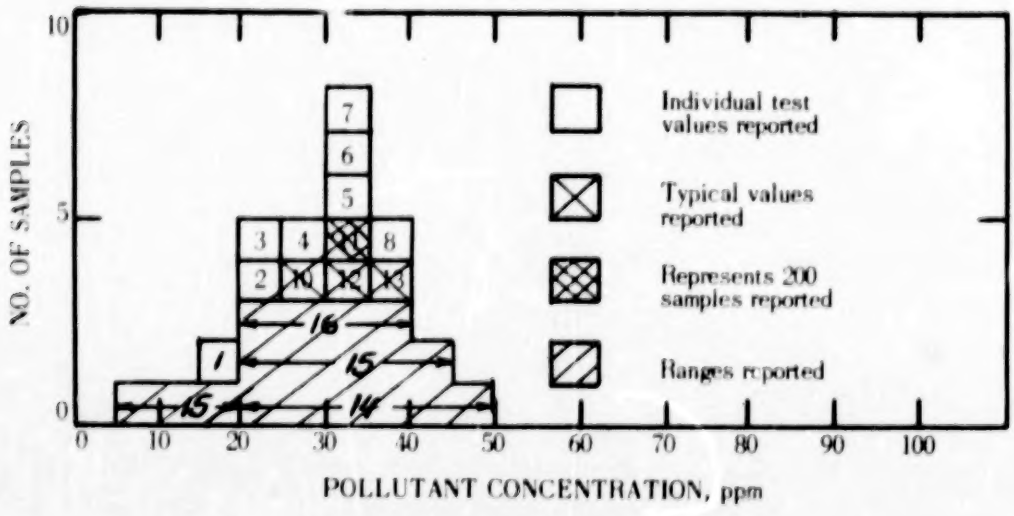
APPENDIX C. METHOD OF REPORTING THE DATA

Emission data for this report fit into three categories: (1) individual test values, (2) typical or general values, or (3) ranges of emissions. For example, if the data for a given pollutant were as follows (values in ppm):

Individual values	Hypothetical references	Typical values	Hypothetical references	Ranges	Hypothetical references
16	1	29	10	20-50	14
21	2	33[a]	11	5-45	15
22	3	34	12	20-40	16
28	4	39	13		
30	5				
31	6				
32	7				
37	8				

[a]Represents 200 samples.

The histogram presenting these data would be constructed as shown in the following figure:



"Ranges" reported were plotted first. The range 20 to 50 from hypothetical reference 14 occupies a row extending from 20 to 50. The range 5 to 45 from hypothetical reference 15 was then plotted in two rows extending from 5 to 45. The range 20 to 40 from reference 16 was plotted in a third row. Next, "typical values" were plotted in squares appropriate to their magnitude. The value 29 from hypothetical reference 10 is shown as a square extending from 25 to 30. The value 34 from hypothetical reference 12 is shown as a square extending from 30 to 35 and the value 39 from hypothetical reference 13 as a square extending from 35 to 40. The typical value of 33 from hypothetical reference 11 was given a special notation because it is based on 200 samples. "Individual" values from references 1 through 8 were then plotted in a fashion similar to the typical values. For this histogram, the extreme range would be 5 to 50 ppm, the most common range 20 to 40 ppm, and the most common values between 30 and 35 ppm. The emission value would be chosen as 32.5 or 33 ppm. In this histogram the hypothetical references are represented inside each square for better understanding of this method of representation. In the text, however, the references are not represented, for the sake of simplicity.

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